# 2024 WEM ESOO Reliability Assessment Methodology Report

Australian Energy Market Operator

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# Release Notice

Ernst & Young ("EY") was engaged on the instructions of the Australian Energy Market Operator ("AEMO", "Client") to provide the reliability assessment underpinning the 2024 Long Term Projected Assessment of System Adequacy (Long Term PASA) for the South West Interconnected System (SWIS) (the "Services").

The results of EY's work, including the assumptions and qualifications made in preparing the report, are set out in EY's report dated 17 June 2024 ("Report"). The Report should be read in its entirety including the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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# Executive summary

EY has been engaged by the Australian Energy Market Operator (AEMO) to provide wholesale electricity market modelling services to assist AEMO in assessing the reliability of supply to meet electricity demand in the South West Interconnected System (SWIS) of Western Australia (WA).

Assessing reliability of supply to meet SWIS demand (reliability assessment) informs the 10-year Long Term Projected Assessment of System Adequacy (Long Term PASA) that AEMO presents annually in the Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO).

The role of the Long Term PASA is to ensure there is sufficient capacity from energy producing systems (thermal, renewable, storage capacity) and Demand Side Management (DSM) to meet the Planning Criterion as defined in clause 4.5.9 of the WEM Rules.

The Planning Criterion sets the SWIS reliability standard and stipulates that there should be sufficient capacity in each Capacity Year to:

- Meet the forecast peak demand plus a reserve margin (this report will refer to this as 'Limb A' of the Planning Criterion)
- Limit expected unserved energy (EUE) shortfalls to 0.0002% of annual energy consumption (this report will refer to this as 'Limb B' of the Planning Criterion).

This reliability assessment has been performed using AEMO's forecasts of the 2024 WEM ESOO demand scenarios for the 2024 Long Term PASA and involves the requirements of the following scope items (presented in further detail below and in Section 3):

- Scope item 1: Demand profile projections
- Scope item 2: Constraint equations development
- Scope item 3: Peak capacity reliability gap assessment
- Scope item 4: Peak Reserve Capacity Target (RCT) forecasts
- Scope item 5: Minimum Capability Classes 1 and 3 capacity determination
- Scope item 6: Battery impacts on operational demand

The purpose of this report is to provide an update to the methodology and assumptions used by EY to provide the 2024 reliability assessment. EY previously provided the 2023 reliability assessment and a detailed modelling methodology report was published alongside the 2023 ESOO.[1] The same modelling framework and many of the same approaches have been applied for the 2024 study, therefore the aim of this report is to highlight regulatory and modelling updates that have resulted in an updated approach. The report is set out as follows:

- Section 1 provides further background and context for the 2024 reliability assessment, noting the updates to the WEM Rules that impact the approach to the study, as well as industry developments such as the new record peak demand recorded in the WEM and AEMO's procurement of Peak Demand Services. This section also provides further detail on the modelling scope items that comprise the 2024 reliability assessment.
- Section 2 sets out a high-level recap of the modelling framework used for the reliability study, and a summary of the approaches that have changed since the 2023 study, including changes to determining Essential System Services (ESS) requirements and the approach to modelling regional capacity shortfalls.
- Section 3 provides a summary of the methodology to deliver the 2024 reliability assessment. Where this has not changed from last year, most of the detail can be found in the Appendices to this report.
- Various Appendices to this report provide further background and detail as required:

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[1] EY (2023) 'AEMO Reliability Assessment 2023'. Available from: [AEMO | WEM Electricity Statement of Opportunities]

- Appendix A: Abbreviations.
- Appendix B: Further detail on the modelling methodology and the approach to modelling each part of the electricity market included in the study.
- Appendix C: Further detail on producing half-hourly demand traces from AEMO's annual forecasts.
- Appendix D: Modelling assumptions.
- Appendix E: Glossary of Terms.

# 1. Introduction

## 1.1 Background

The main results of the reliability study are presented in the 2024 WEM ESOO document. It should be noted that EY performed the reliability assessment accompanying the 2023 WEM ESOO and provided a comprehensive methodology and assumptions report to accompany the reported reliability outcomes, which can be found on AEMO's website and can be referred to for further detail on approach.[2]

EY has used the same modelling framework (see Section 2.1), and in many instances the same methodology and approach to similar scope items as detailed in the 2023 study. Where these assumptions and approaches remain the same, the previous report and the appendices in this report can be referred to, with the main purpose of this report to set out where new or revised assumptions and approaches have been required, either due to new WEM Rules requirements, or different scope items required.

This section provides the following:

- Section 1.2 summarises the changes to the WEM Rules since the 2023 study and other key developments in the WEM since the previous study
- Section 1.3 summarises the key industry developments in the year since the previous reliability assessment was carried out
- Section 1.4 sets out the scope items that were carried out by EY to provide AEMO with the 2024 reliability assessment
- Section 1.5 provides the high-level approach and remaining report structure.

## 1.2 Updates to the WEM Rules and impact on approach to 2024 reliability assessment

Where this report refers to the 'current' WEM Rules, it refers to the version of the Rules as at 1 April 2024. The key revisions to the WEM Rules that have necessitated a change in approach to this year's reliability assessment include:

- Changes to the Planning Criterion
- Introduction of the Availability Duration Gap Load Scenario and the Availability Duration Gap
- Introduction of Capability Classes to replace Availability Classes
- Changes to scenarios to assess the Planning Criterion
- Updates to requirements in determining the Reserve Capacity Target
- Updates to requirements for Demand Side Programmes (DSP)
- Increased emphasis on assessing regional shortfalls

These revisions are described in further detail below.

### 1.2.1 Revisions to the Planning Criterion

A reliable power system has enough generation, storage, demand response and network capacity to supply customers with the energy they demand with a very high degree of confidence. The reliability of a power system is planned for through long-term projections of supply adequacy compared against the expectations of demand.

[2] EY (2023) 'AEMO Reliability Assessment 2023'. Available from: AEMO | WEM Electricity Statement of Opportunities

In the WEM, reliability is planned for using planning criteria that set a target for a capacity reserve margin and a threshold for expected annual unserved energy that may result from supply shortfalls (the Planning Criterion). The Planning Criterion is comprised of two components (referred to as 'Limb A' and 'Limb B' in this assessment). Both Limb A and Limb B must be satisfied, with the Planning Criterion stipulating that there should be sufficient available capacity in the SWIS in each Capacity Year to:

- Meet the forecast peak demand plus a reserve margin (Limb A of the Planning Criterion)
- Limit expected unserved energy shortfalls to a set percentage of annual energy consumption (Limb B of the Planning Criterion).[3]

While both Limbs must be satisfied, the greater of the Limb A and Limb B requirements sets the Reserve Capacity Target (RCT) for individual years of the Long Term PASA Study Horizon (which refer to Capacity Years 2024-25 to 2033-34).

The requirements of both Limbs have been updated in the WEM Rules since the 2023 reliability assessment, as set out in Table 1.

**Table 1: Revisions to the Planning Criterion between the 2023 and 2024 reliability assessments**

| Limb requirement | Requirement at the time of 2023 study | Requirement at the time of 2024 study |
|---|---|---|
| **Limb A: Reserve margin** | Greater of:<br>► 7.6% of peak demand<br>► the largest supply contingency | Greater of:<br>► peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages<br>► the largest supply contingency |
| **Limb B: expected unserved energy (EUE) percentage as a proportion of annual energy consumption** | Not to exceed 0.002% | Not to exceed 0.0002% |

Further detail on each of the components of Limb A, and EY's approach to determining Limb A and Limb B requirements can be found in Section 3.4.

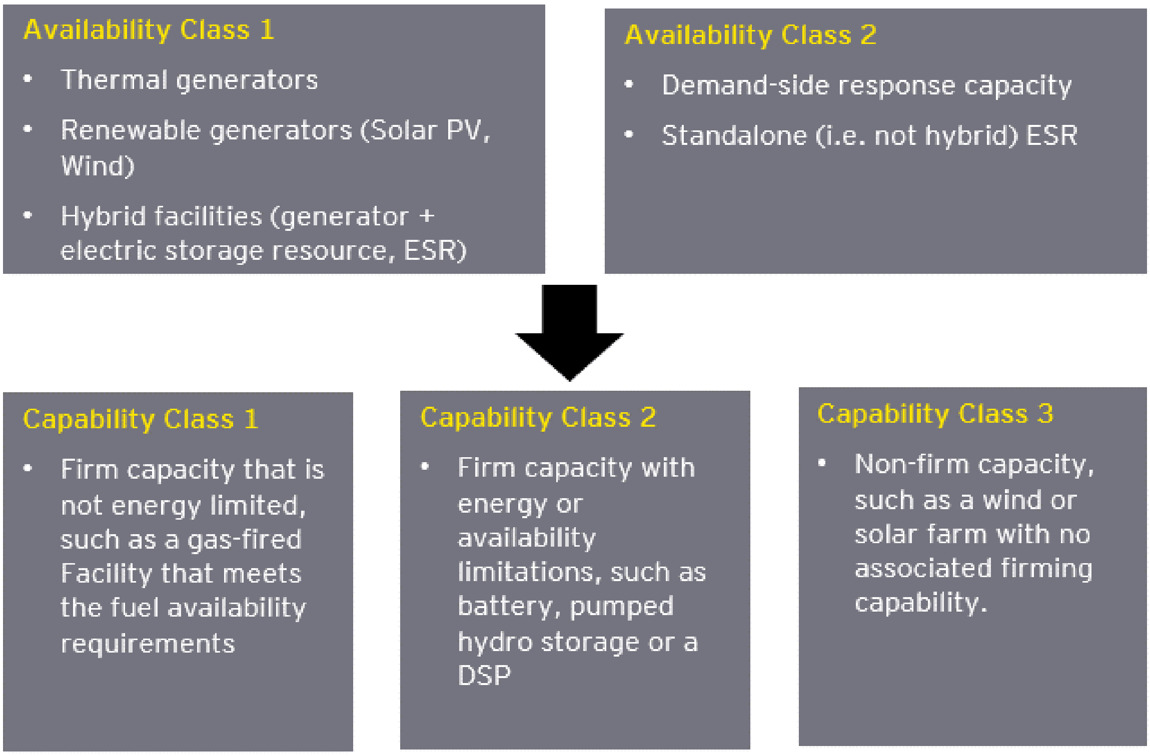
### 1.2.2 Introduction of Capability Classes

Three Capability Classes defining different categories of capacity have replaced the previous two Availability Classes (see Figure 1), with the WEM Rules requiring AEMO to determine the minimum capacity required to be provided by Capability Class 1 and Capability Class 3 capacity.[4] The impact of these changes on the methodology to determine the balance of capacity between classes is described further in Section 3.

[3] Clause 4.5.9 of the WEM Rules.

[4] See Clause 4.11.4 and 4.5.12(i).

**Figure 1: Previous Availability Classes and current Capability Classes**




### 1.2.3 Changes to scenarios to assess the Planning Criterion

At the time of the 2023 study, the WEM Rules required AEMO to assess the extent to which anticipated installed capacity in the WEM is capable of satisfying the Planning Criterion (and identify shortfalls) for a low, expected and high demand scenario.

The current version of the WEM Rules only requires this assessment to be made for the one in ten-year peak demand assuming expected demand growth.[5]

Therefore, this year's report focuses on the 10% POE expected demand scenario for presenting results on expected unserved energy (EUE) outcomes and comparing outcomes against the Planning Criterion.

### 1.2.4 Updates to requirements in determining Reserve Capacity Targets

The WEM Rules requires AEMO to forecast the Peak Reserve Capacity Target for each Capacity Year during the Long Term PASA Study Horizon. The current version of the WEM Rules specify that this determination should assume no network congestion, as the Reserve Capacity Mechanism considers the impacts of network congestion under the Network Access Quantity (NAQ) framework.[6] This requirement is assessed by running EY's dispatch model in the absence of transmission thermal network constraint equations. Section 3 provides further detail on the methodology for determining the RCT.

### 1.2.5 Updates to requirements for Demand Side Programmes (DSP)

At the time of the 2023 study, DSP facilities were modelled to provide up to 200 hours of demand response

[5] See Clause 4.5.10.

[6] See Clause 4.5.10(b).

over the year, based on the minimum requirements outlined in the WEM Rules at the time. For the years 2024-25 and 2025-26, the modelling will continue to apply the requirement of up to 200 hours response. Reflecting changes in the WEM Rules, from 2026-27 onwards the requirement for DSP will fall to 50 hours (or 100 Trading Intervals).[7] All other aspects of DSP treatment in the modelling remain the same and are set out in further detail in Section B.1.4 of Appendix B.

### 1.2.6 Increased emphasis on assessing regional shortfalls

The current WEM Rules now explicitly require AEMO to 'identify and assess any potential capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors and which cannot be addressed by additional Peak Capacity outside that sub-region'.[8]

To assist with this assessment, EY's analysis reports on the top binding and violating transmission network constraint equations, similar to the outcomes presented in EY's 2023 report, however given this Rules requirement now adds another layer of more detailed regional analysis. This approach is set out in more detail in Section 2.2.4 and Section 3.

## 1.3 Industry context

To provide more context for the WA Wholesale Electricity Market for this reliability assessment, the following represents key developments over the last year:

- The retirement of State-owned coal units Collie and Muja D are still planned as per the WA State Government's public announcements (for late 2027 and late 2029 respectively).[9] The 400 MW Muja C coal-fired power station was due to fully retire by October 2024, however the WA Government announced that the retirement of one of its units (Unit 6) would be pushed back by six months to April 2025 and operate in reserve outage mode to help mitigate supply risks over the summer months.[10,11]
- The 2023 WEM ESOO for the first time, identified potential generation capacity deficits across the whole forecast period which was a notable change from the 2022 outlook. Based on forecast rising demand and scheduled plant retirements, the 2023 WEM ESOO forecast that based on existing and committed capacity, an additional 1,118 MW of capacity would be required by 2026-27 increasing to 4,000 MW by 2032-33.[12]
- On 18 February 2024, during the 17:55 interval, AEMO recorded the highest maximum operational demand of 4,233 MW which broke the previous record of 4,040 MW from Q3 2023.[13,14].
- Further to the NCESS for Reliability Services for 2024-26, AEMO requested the WA Coordinator of Energy to trigger a further NCESS for Reliability Service, covering the period 2025-27.[15] The request was based on AEMO's analysis that forecast capacity to meet the 2025-26 Reserve Capacity Requirement presents a significant risk to Power System Security and the effectiveness of the Reserve Capacity Mechanism (RCM) to mitigate capacity shortfalls. Based on those conclusions, the Coordinator of Energy determined that an NCESS for Reliability Services should be triggered for two years commencing 1 October 2025. A call for

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[7] See WEM Rules Glossary definition of 'Peak Demand Side Programme Dispatch Requirement'.

[8] See Clause 4.5.10(c).

[9] WA Government (2022). Available from: State-owned coal power stations to be retired by 2030 with move towards renewable energy

[10] WA Government (2023). Available from: Muja C Unit 6 in reserve mode and online for summer 2024-25

[11] Note that for the purposes of the reliability study modelling, Muja G6 is assumed to be unavailable from 1 October 2024.

[12] AEMO (2023) 'WEM ESOO 2023 Infographic', available from: https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2023/2023-wem-esoo-visual-overview.pdf?la=en

[13] AEMO (2024) 'Quarterly Energy Dynamics Q1 2024'. Available from: qed-q1-2024.pdf (aemo.com.au)

[14] Note that the demand figures presented here represent the 5-minute interval demand and differ to other reported measurements of demand that present demand or generation over a 30-minnute interval for example.

[15] NCESS (Non-Co-optimised Essential System Services) can be triggered by the Coordinator of Energy following a request, on this occasion from AEMO. Following a procurement process seeking up to 830 MW of peak capacity, and 269 MW of minimum demand service, AEMO entered into contracts with five providers for eleven projects to provide services over 2024-26. These contracts are to provide up to 630 MW of Peak Demand Service and 446 MW of Minimum Demand Service (for further information see AEMO | Tenders and Expressions of Interest for NCESS –Reliability Services 2024-26 (WA).

submissions was issued in November 2023, seeking to procure 436 MW of Reliability Services over that time.[16]

In light of the above, we note that:

- Even if there is sufficient capacity to satisfy the annual peak demand interval, it may transpire that demand in other intervals is not fully satisfied by capacity available in these intervals, resulting in instances of unserved energy.[17]
- The assessment of Limb B of the Planning Criterion can result in annual EUE volumes exceeding the 0.0002% standard, and Limb B can be the driver of the RCT (if it is higher than Limb A in required installed MW terms), particularly given the more stringent requirement of Limb B in the revised market rules described above.

## 1.4 Required scope items

Table 2 summarises the scope items carried out by EY to deliver the reliability assessment to inform the Long Term PASA for the 2024 WEM ESOO. The scenarios and modelling timescales are described and are based on WEM Rules requirements.

**Table 2: Overview of scope items of the 2024 reliability study**

| Scope item | Description | Key objective | Assessment time period and scenario |
|---|---|---|---|
| **Scope item 1** | Development of time-sequential, half-hourly underlying and operational demand projections for each of the required Capacity Year and demand scenarios using AEMO's peak demand and annual energy forecasts, integrating the impact of Consumer Energy Resources (CER). | Serve as an input to the reliability assessment. | ► 2024-25 to 2033-34<br>► 10% and 50% POE under each of the low, expected, and high demand scenarios. |
| **Scope item 2** | Development of constraint equations taking into consideration anticipated installed capacity (AIC), demand forecasts, appropriate transmission configurations and limits and anticipated network augmentations. | Required to ensure that the technical limits of the system are not exceeded. | ► 2024-25 to 2033-34<br>► 10% POE under expected demand scenario. |
| **Scope item 3** | Assessment of the extent to which the AIC of the Energy Producing Systems (EPS) and Demand Side Programme (DSP) capacity can satisfy the Planning Criterion (including consideration of network congestion) including: [18]<br>► identifying any Peak Capacity shortfalls for the scenario specified under clause 4.5.10(aA) of the WEM Rules.<br>► identifying and assessing any potential Peak Capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors, and which cannot be addressed by additional Peak Capacity outside the subregion, as required under clause 4.5.10(c) of the WEM Rules.<br>► identifying any potential transmission, generation, storage, or demand side capacity augmentation options to alleviate capacity shortfalls identified in clauses 4.5.10(aA) and 4.5.10(c) of the WEM Rules. | Identify, analyse and characterise capacity and reliability shortfalls under both Limbs of the Planning Criterion | ► 2024-25 to 2033-34<br>► 10% POE under expected demand scenario. |

[16] AEMO | Expressions of Interest and Tender for NCESS – Reliability Services 2025-27 (WA)

[17] In real-time operation of the power system (especially with a high share of intermittent renewable capacity), generation capacity during the peak or other intervals may become fully or partially unavailable due to e.g., forced outages or insufficient renewable resource availability.

[18] The AIC is determined as existing SWIS installed capacity (generation, storage, DSP) less existing capacity retirements + committed capacity, as advised by AEMO.

| Scope item | Description | Key objective | Assessment time period and scenario |
|---|---|---|---|
| **Scope item 4** | Forecast the Reserve Capacity Target (RCT) for each Capacity Year during the Long Term PASA Study Horizon in accordance with clause 4.5.10(b) of the WEM Rules to meet the Planning Criterion in that year under the scenario described in clause 4.5.10(a)(iv) of the WEM Rules. | Determine whether the RCT is set by Limb A or Limb B and quantify the RCT (in MW). | ► 2024-25 to 2033-34<br>► 10% POE expected scenario |
| **Scope item 5** | Determine the minimum capacity required to be provided by Capability Class 1 and Capability Class 3 and an appropriate mix of the additional Capability Class 1 and Capability Class 3 capacity required if any shortfall is identified for the required Capacity Year and demand scenario. | Identifying the balance of capacity between different Capability Classes. | ► 2026-27<br>► 10% POE peak demand under the Expected demand scenario (as adjusted for the Availability Duration Gap Load Scenario). |
| **Scope item 6** | Modelling of battery energy storage to determine the annual and interval level impact of battery charging and round-trip efficiency losses on operational demand. | Impact of round-trip efficiency losses on operational demand. | ► 2024-25 to 2033-34<br>► 10% POE expected scenario |

## 1.5 High-level approach and report structure

The remainder of this report is structured as follows:

- Section 2 presents a high-level overview of the modelling framework applied to carry out the 2024 reliability assessment and sets out the assumptions and approaches that have changed from the 2023 reliability assessment. All other input assumptions that remain the same are detailed further in the appendices to this report.
- Section 3 presents the methodology and how EY's electricity market model (2-4-C) is deployed to undertake the elements of the reliability assessment. Key aspects of how EY has derived AIC EUE, comparison of Limb A and Limb B to the Planning Criterion, determination of Capability Classes and battery round-trip efficiency losses modelling is described.
- Appendices provide more detail as follows:
    - Appendix A provides the abbreviations list.
    - Appendix B sets out the detail behind the modelling framework.
    - Appendix C provides the detail of EY's approach to developing half-hourly demand inputs based on the annual demand inputs provided by AEMO.
    - Appendix D provides a summary of the data inputs provided by AEMO.
    - Appendix E provides the glossary of terms.

# 2. Modelling framework and input assumptions

## 2.1 High-level overview of the 2-4-C® model

For the reliability study, EY used its in-house 2-4-C® software suite, which consists of a co-optimised energy market and Essential System Service (ESS) dispatch engine, and several software tools that are used to develop input data and analyse output data.

The 2-4-C dispatch engine replicates key aspects of electricity market dispatch engines such as the WEM Dispatch Engine (WEMDE) that is used by AEMO in operating the Real-Time Market (RTM) which began operation on 1 October 2023.

The 2-4-C model is designed to represent the key characteristics of the WEM and the generation, energy storage and demand-side response providers that participate in the RTM. Each Facility is modelled explicitly and is dispatched in response to the demand forecast, power system security requirements, transmission network capability and Facility availability for each half-hour according to modelled bidding assumptions which are a representation of RTM Submissions.[19]

The 2-4-C® dispatch engine has been applied in this engagement at a half hourly resolution to perform time-sequential dispatch modelling over the study horizon. Modelling on a time-sequential basis helps to capture a range of important market aspects that can impact reliability outcomes:[20]

► **Renewable resource variability and weather-driven demand patterns**: EY's modelling of future demand patterns bases all the inter-temporal and interspatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (referred to as reference years). This reference year approach is described in more detail in Appendix C and is applied on a time-sequential basis. This means that the same weather factors that drive variability in demand from one Trading Interval to the next are also captured in the resource availability of wind and solar generation (large-scale and behind-the-meter in the case of solar) in future modelled years. In this way, the correlation between when renewable resources are available and when customers use energy is captured in the datasets.

► **Generator and storage forced outages**: Using time-sequential modelling captures the duration (and thus impact) of generator and storage outages throughout contiguous intervals in a year, as opposed to modelling based on data 'blocks', i.e. only selected representative days or other periods of a year.

► **Ramp rate limitations**: The ability of a modelled Facility (generation, storage, demand-side response provider, or a combination thereof) to contribute to meeting energy demand (or provide ESS) can depend on how quickly it can increase or decrease its output from one Trading Interval to another. Ramp rates may not bind often but in the context of a reliability study where EUE can result because of discrete step changes to supply availability, it is important to capture the ability of generators or DSM to ramp up or ramp down quickly.[21]

► **Modelling of storage**: The ability of storage to provide energy in a given interval depends on its state of charge (or reservoir level for pumped hydro). For the purpose of this reliability study, it is assumed that storage in the market will be deployed to avoid unserved energy as a priority.[22] Time-sequential modelling captures the operation of storage from one interval to the next and take account of the level of

[19] As explained in Appendix B, the modelling will assign bidding profiles to every Facility, however for the purposes of a reliability study, the actual values of the bids are of secondary importance (as Facilities will generate if available (subject to any constraints) as required to avoid unserved energy.

[20] By time-sequential data we mean time series of 17,520 (or 17,568 for leap years) consecutive 30-minute interval datapoints for each modelled year, with outcomes in the previous interval being relevant for the currently modelled interval.

[21] Generator ramping relates to generation Facilities as well as the generator side of storage facilities.

[22] Though note that the modelling to estimate the impact of battery charging and discharging on operational demand takes a different approach, as set out in Section 3.6.

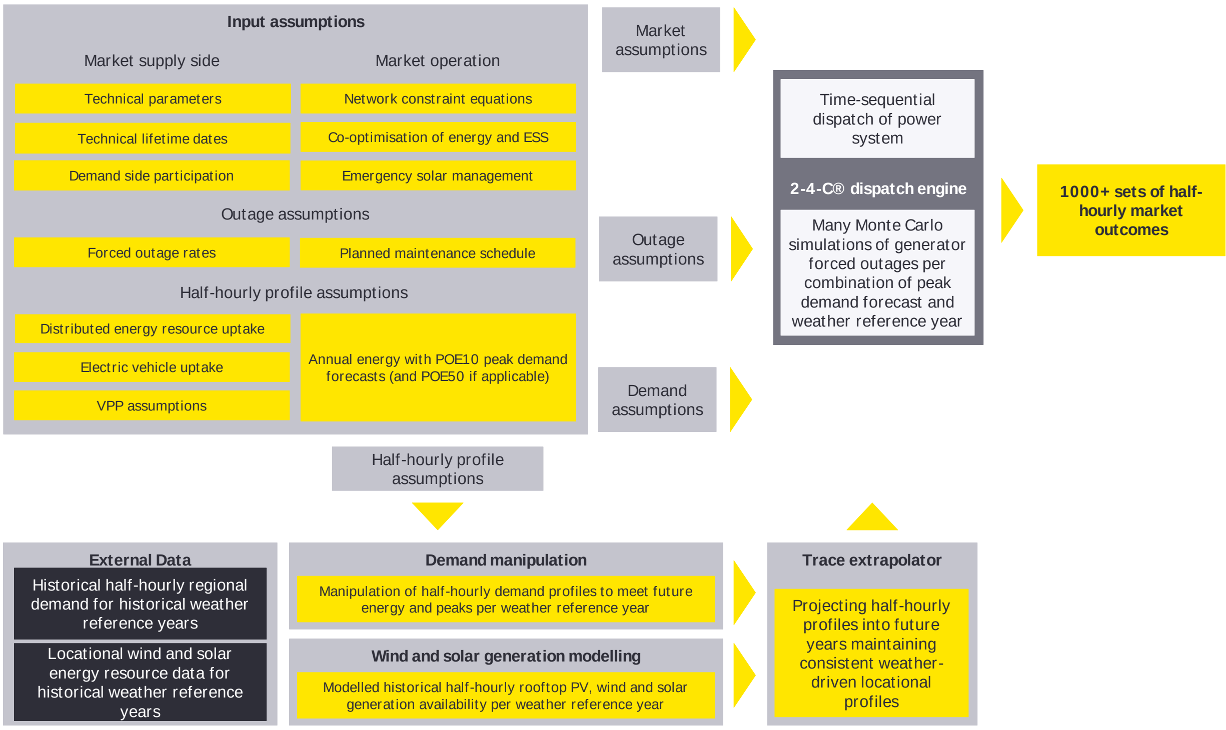
the storage remaining in each particular interval. It also allows the storage to flex between charge and discharge from one interval to the next in response to changing demand and supply conditions.

- **Transmission network limitations**: Constraint equations in trading interval are evaluated by using the generation dispatch from the previous trading interval period t-1, to calculate terms in the right-hand side of the equation and to enable the left-hand side of the equation to be solved. EY's 2-4-C model is time-sequential, dispatched for every half-hour and has the required functionality.

A large number of Monte Carlo iterations have been performed in the market modelling to capture the impact of forced (unplanned) generator outages. We believe that discrete generator forced outage modelling combined with multiple weather reference years are critically important to provide a reasonable estimate of the unserved energy that may be incurred for different operating conditions.[23]

**Figure 2** presents a high-level overview of the range of input assumptions, and the interactions between the 2024 WEM ESOO scenarios and the 2-4-C dispatch engine.

**Figure 2: High-level overview of the interactions between input assumptions, 2024 WEM ESOO demand scenarios and the 2-4-C model**




The approach to each of the modelling elements is described in further detail in Appendix B, Appendix C, and Appendix D. Key changes that were implemented this year include:

- In the 2023 reliability assessment, AEMO provided externally developed thermal network constraint equations, whereas this year, EY has developed constraint equations. The approach to this is set out in Section 3.2.

- The approach to determining the amount of Contingency Raise requirement has been updated for the 2024 study. The approach to this is set out in Section 2.2.1.

[23] This reliability assessment has used 12 historical weather reference years which applies half-hourly weather patterns to wind availability and solar availability, and 100 iterations of Monte Carlo simulations applied to each year of the study period. This equates to 1,200 simulations applied to each year in the 10-year study period.

► The approach to modelling of Limb B has been revised, following an update to the modelling of capacity for reliability, as described in Section 2.2.2

► The modelling of hydrogen electrolyser load has been updated this year, aimed at capturing potential energy demand over the year more fully, as set out in Section 2.2.3.

► The approach to assessing regional shortfalls has been extended, given the increased requirements in the WEM Rules – this approach is described in Section 2.2.4.

## 2.2 Modelling assumptions and approaches updated from the 2023 reliability assessment

### 2.2.1 Updated approach to Essential system services (ESS)

2-4-C simulates the co-optimisation of the WEM balancing energy market and the following ESS markets to assess annual unserved energy against the reliability standard:

► Regulation Raise (formerly Load Following Ancillary Service (LFAS) up ).[24]

► Contingency Reserve Raise (formerly Spinning Reserve Ancillary Service).[25]

Modelling ESS raise markets in this reliability study will help to identify intervals where limiting dispatch on certain generation Facilities to reserve headroom for ESS raise services may contribute to shortfalls in generation supply availability to meet demand.

A number of the aspects of the modelling of ESS are unchanged from the 2023 reliability assessment:

► Only the raise markets are included in the modelling (rather than the lower markets, on the basis that only these markets have a potential impact on reliability outcomes).

► ESS provision is prioritised over energy provision – although in operational timeframes AEMO may choose to appropriately balance the risks between meeting ESS obligations or serving system demand, for the purposes of the reliability assessment the modelling ensures that ESS obligations are not compromised. [26,27]

► New entrant storage is assumed to participate in the modelled ESS raise markets and is bid into the market after existing service providers. Whilst it is possible that storage may displace existing participants in these markets, this simplified modelling implementation has minimal impact on the key outcomes of the reliability assessment as the same quantity of headroom is reserved.

The main changes to the modelling of ESS for the 2024 study are:

► Updated formula for determining the Regulation Raise requirement: AEMO has estimated the minimum Regulation Raise requirement using the Essential System Services framework, ensuring frequency is maintained within the Normal Operating Frequency Band. This accounts for the increasing penetration of intermittent generation, particularly distributed PV (DPV). The requirement has modestly increased compared to the 2023 WEM ESOO reflecting AEMO's updated forecasts to manage power system frequency, driven mainly by the growing impact of DPV, as well as an updated approach to apply installed capacity (instead of forecast Reserve Capacity) for new wind and solar generation.

[24] Frequency regulation services assists in ensuring that system frequency stays between the range of 49.8 and 50.2 Hz for normal operating conditions

[25] Contingency Reserve Raise is designed to contain under-frequency excursions above 48.75 Hz.

[26] These decisions would be based on relevant information only available in operational timeframes including but not limited to, forecasts, volatility, contingency size and modelled frequency outcomes.

► Updated approach to determining the Contingency Raise Requirement: In the 2023 study, the Contingency Raise Requirement was set as a static MW number determined exogenously to the model and applied in every half-hour interval, representing a conservative approach to the headroom required to be reserved for potential Contingency Raise requirements. For this year's study EY has implemented a more dynamic approach, whereby the model calculates the largest contingency from interval to interval and uses this information to set the requirement. The requirement therefore updates in each interval, and is also calculated for each of the 100 iterations across each of the 12 historical weather reference year model runs.

### 2.2.2 Updated approach to determining Limb B capacity for reliability

In the 2023 reliability assessment as agreed with AEMO, EY determined the capacity required to limit EUE to no more than allowed by the reliability standard by firstly modelling AIC and comparing the EUE outcomes to the reliability standard (then 0.002% of annual energy consumption).

If there was a shortfall against Limb B (i.e. EUE was above 0.002%) the model added generic capacity (capacity for reliability, CFR) which was assumed to be unconstrained and fully reliable. It was also assumed to bid higher than any other capacity. This was a conservative approach, as it meant that this capacity was not available in the model for storage to charge from, nor did it help to preserve DSP running hours.

In this year's analysis, it has been assumed that the CFR is available for storage to charge, and to help preserve the running hours of DSP (i.e. it bids lower in the market than these technologies). Based on a significantly changing supply mix (the entry of large amounts of storage) and the need in future for a mix of new technologies to enter the WEM, this assumption was updated to allow CFR to bid lower in the market and be available for storage to charge from. The impact of this updated assumption on the methodology to determine Limb B is set out in Section 3.4.

### 2.2.3 Updated approach to modelling hydrogen electrolyser load

In the 2023 assessment it was agreed with AEMO that EY would input hydrogen electrolyser load as a flat load at 10 percent of its installed capacity. This was on the basis of the assumption that demand from hydrogen production would turn down to 10 per cent of its installed capacity at times of operational peak and to 10 percent at the time of underlying peak, and at times of 'grid emergencies' – including instances of otherwise unserved energy.

For modelling implementation this meant hydrogen demand was input as a flat load at 10 per cent of installed capacity to ensure it reflected this 10 percent at times of peak demand and otherwise unserved energy.

For this year's study it has been agreed with AEMO to model hydrogen load differently such that it turns down to 10 per cent of installed capacity at peak times but has demand at other intervals that means its full energy consumption over the year is reflected in the modelling. As a simplistic approach this was applied as hydrogen turning down to 10 per cent during peak times (the modelling applied a time band of 4.30pm to 9.30pm) and then increasing in other intervals. This captures the full energy consumption of hydrogen over the year and increases the reported annual EUE, but the modelling found it did not change the Limb B requirement (as the capacity required to meet EUE over the year is also sufficient to cover this increased hydrogen load at other times).

### 2.2.4 Approach to assessing regional shortfalls

As well as determining the RCT, the reliability assessment identifies regional capacity shortfalls and reports on EUE outcomes including the impact of network constraints. Although the RCT determination is carried out without network constraints applied in the modelling, thermal network constraints are included in the reliability gap assessment.

In the 2023 study, EY published the details for the top ten binding and violating constraints to indicate where:

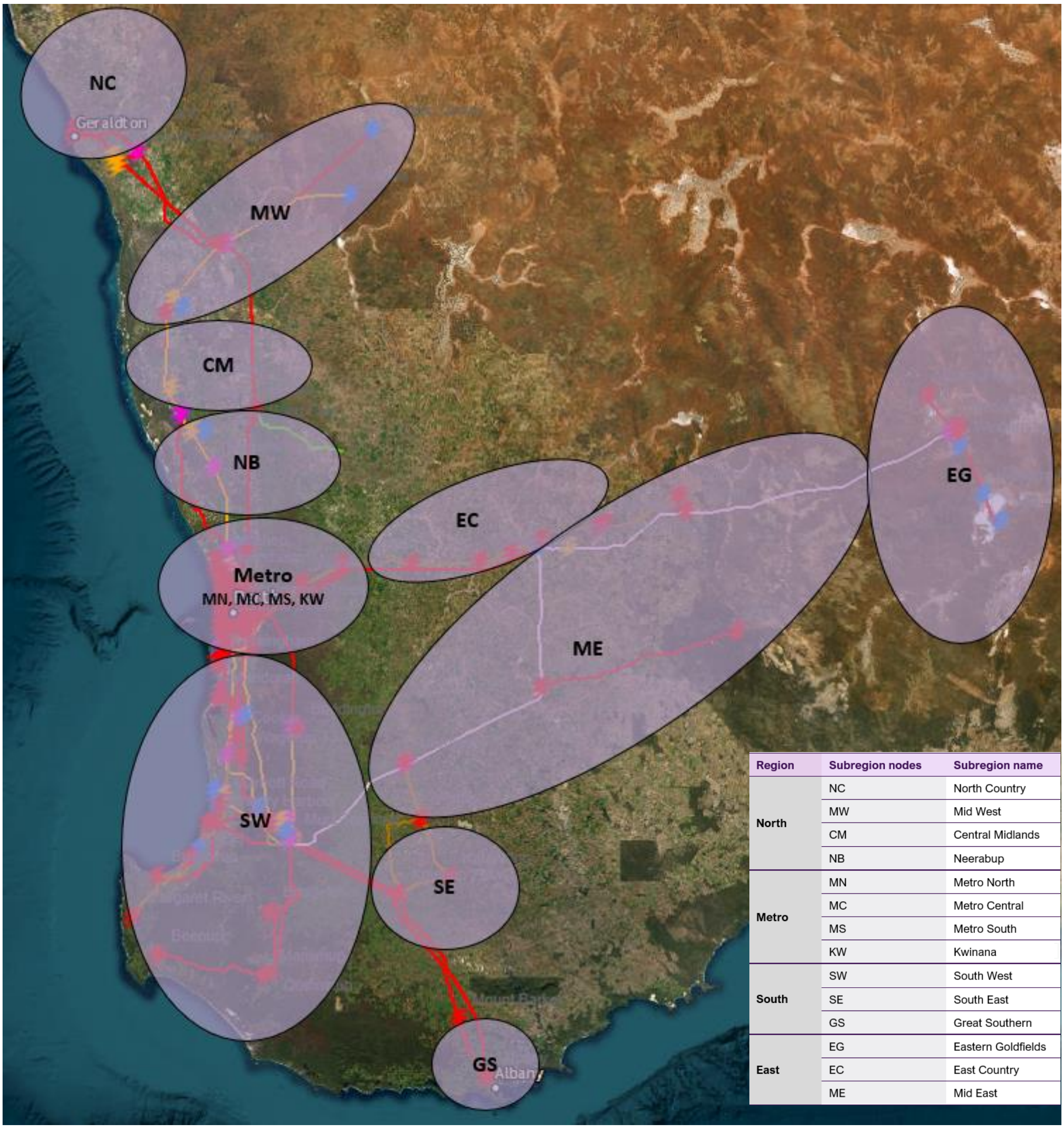
- In the case of binding constraints that a part of the power system is modelled as being operated at or very close to a design limit – and where transmission network capability may be impacting on the dispatch of generation facilities in the electricity market.
- In the case of violating constraints, a potentially insecure power system and where load shedding may be necessary to keep the power system secure. Violating constraints indicates those parts of the network that may need to be reinforced to maintain power system security, as a generation dispatch solution was not found in the dispatch simulations.

For the analysis this year, the WEM Rules specifically require AEMO to consider regional capacity shortfalls – that is EUE occurring in sub-regions of the SWIS that cannot be addressed by additional Peak Capacity outside that sub-region.

**Regions and subregions**

The SWIS regions and subregions are presented using the nodal configuration in the SWIS Whole of System Plan and later refined for the SWIS Demand Assessment as shown on the map below.

**Figure 3: High-level overview of the areas assessed for regional reliability assessment**




| Region | Subregion nodes | Subregion name |
|---|---|---|
| North | NC | North Country |
| | MW | Mid West |
| | CM | Central Midlands |
| | NB | Neerabup |
| Metro | MN | Metro North |
| | MC | Metro Central |
| | MS | Metro South |
| | KW | Kwinana |
| South | SW | South West |
| | SE | South East |
| | GS | Great Southern |
| East | EG | Eastern Goldfields |
| | EC | East Country |
| | ME | Mid East |

## Modelling of EUE Generators

Combined with modelling different weather profiles, a set of transmission network thermal limitations and MC simulations of thermal generator outages, regional shortfalls can be observed in the reliability modelling through a set of 'EUE Generators' that are located strategically across the SWIS. These generators are dispatched in the case of a supply shortage and/or to relieve transmission network constraints, and are placed at the lowest priority of the bid merit order.

The approach undertaken in this Reliability Modelling is to select different connection points across the SWIS and model an EUE Generator at each connection point in a steady state AC load flow model. These connection points are selected based on expectations around future demand growth and regions that are known to be constrained now, and possible in the future. These connection points are located only at 330 kV and 132 kV connection points.

The steady state load flow models are used by EY to construct a set of thermal constraint equations that include all terms for existing and future generators captured in the expected scenario, and all EUE Generators. This ensures that the dispatch of all AIC and EUE Generators are subject to locational considerations of transmission network import and export capability.

The EUE Generators are provided a specific energy bid profile to ensure they are dispatched only after all existing generation, DSP and storage has been exhausted, and considering impacts on transmission network limitations. They are modelled as perfectly reliable (no forced outage rates) and do not have limits on ramp rate or installed capacity.

Where the EUE Generators are observed to be dispatched, this reflects a possible EUE or capacity shortfall. It reflects locations on the SWIS where customer demand can only be served by dispatching fictitious generators that are the most expensive in the BMO, as a result of inadequate local generation supply and insufficient import power transfer capability from the transmission network.

**Regional shortfalls**

Regional shortfalls are reported across two metrics:

- Annual EUE, which represents the annual customer demand in MWh that is observed across a capacity year, based on equally weighted likelihoods for different weather reference year conditions and iterations of MC outages; and

- Capacity shortfalls, which represents the maximum shortfall in each node of the SWIS, quantified by observing the maximum dispatch of unserved energy generators located at different parts of the SWIS.

Each EUE Generator is assigned to a region and subregion. The sum of dispatch and shortfall is observed by summing up all generators in each region and subregion.

**Future generation and network development**

In the absence of any further network augmentation commitments, the SWIS will experience network congestion and system security risks.

For modelling purposes, any quantification of EUE is misleading if it fails to account for the potential of network development to resolve system security issues, noting that a significant amount of transmission network would be needed to facilitate the connection of the magnitude of demand forecast across the study period. Furthermore, EUE can be misreported in market simulations when constraint equations violate, leading to EUE that can be significantly under-reported.

When formulating network augmentation assumptions across the study period, EY considers a combination of simulation outcomes that observes the impact of future demand growth on the SWIS, highlighting areas where system security risks may emerge due to inadequate local supply and transmission network capability.

# 3. Methodology to deliver the 2024 reliability assessment

## 3.1 Scope item 1: Demand profile projections

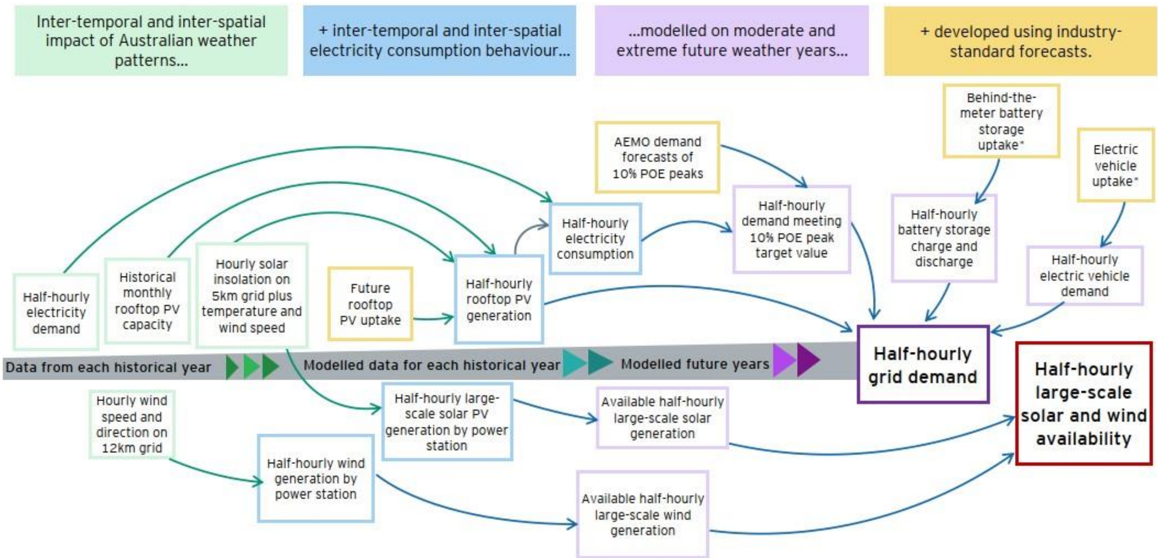
EY's approach to forward-looking half-hourly modelling is to base all the intertemporal and interspatial patterns in electricity demand, wind energy and solar energy on the weather resources and consumption behaviour in one or more historical years (referred to as reference years).

This helps to retain the relationships between time of day, consumption behaviour and renewable resources. We consider this an essential aspect of modelling supply reliability, and allows our model to capture high impact, low probability (HILP) events induced by weather conditions and demand variability.

We believe that retaining correlation (or temporal synchronisation) between demand and renewable resource data is fundamental to assessing the reliability / operability of power systems, particularly with increasing penetration of wind and solar generation.

Figure 4 depicts EY's methodology to modelling future half-hourly electricity demand, rooftop PV available generation as well as large-scale wind and solar PV available generation.

**Figure 4: Flow diagram showing EY's use of a historical year of electricity demand and weather conditions data to produce a time-sequential, half-hourly, forward-looking dataset for dispatch modelling**




EY's approach to creating the half-hourly demand inputs for the dispatch model is based on disaggregating demand into the various components that influence the shape of demand across each day and year. Once we take account of these separate elements, the remaining demand profile is considered to be a 'fixed shape consumption' (FSC) which is driven by consumer energy use patterns in response to weather from half hour to half hour. We consider these patterns fixed across future years, modified for future energy and peak demand projections.

Putting together the half-hourly demand inputs for the dispatch model involves the following key steps:

- Develop historical half-hourly operational demand profiles (based on data published by AEMO)
- Derive half-hourly profiles for historical rooftop PV and small non-scheduled PV (PVNSG) based on historical capacity and data collected by EY on historical solar resource.
- Derive half-hourly historical FSC traces for each weather reference year to be modelled

- ► Implement EY's load forecasting methodology which creates future FSC profiles by targeting the same underlying annual peak for each historical weather reference year (as provided by AEMO for the reliability study).
- ► Derive projections of each individual component of demand (see Appendix B) which when added to the FSC profiles represent the half-hourly operational demand required to be met from WEM Facilities (and also match the annual energy consumption provided by AEMO over each forecast year).
- ► Check the operational peak outcomes and adjust if necessary to align with AEMO's provided projections of operational peak demand.

Further detail of EY's overall approach and approach to individual demand components can be found in Appendix C.

## 3.2 Scope item 2: Development of Constraint Equations

For the 2024 Reliability Assessment EY has developed transmission network constraint equations. The WEM operates under a fully constrained network access arrangement, and the Reliability Assessment is required to account for the SWIS transmission network capabilities when determining sufficient capacity to limit EUE to 0.0002% of annual energy consumption.

These transmission network constraint equations are linearised mathematical expressions that represent the technical envelope that the SWIS must operate within. They model the maximum power transfer that can flow on transmission network elements before a limitation is reached[28]. Distribution network limitations are not modelled in this reliability assessment.

The objective of these transmission network constraint equations is to prevent overloading of any transmission network element and to keep the power system secure. The constraints take two forms:

- ► N-0 constraints: These are formulated to avoid the overloading of a monitored element during system normal operation. This ensures the system is operating in a satisfactory operating state.
- ► N-1 constraints: These are formulated to prevent the overloading of transmission network elements should any single credible contingency occur (i.e., the outage/failure of a transmission network element). This ensures the system is operating in a secure operating state.

In our 2-4-C modelling, N-1 constraints are enforced pre-contingently, that is, at all times. This ensures compliance with limit advice provided by Western Power and is consistent with how the SWIS and the WEM are operated in the RTM.[29]

The constraint equations are formulated based on a set of detailed power system load flow studies to derive a flow equation (representing the active power flow on a transmission network element) and the limit equation (representing the limit of that transmission network element).

The mathematical expressions are typically formulated such that the sum of terms on the left-hand side (LHS) of a constraint equation must be less than or equal (or greater than or equal) to the sum of terms on the right-hand side (RHS) of a constraint equation. Controllable generation terms are typically assigned to the LHS and a

[28] Constraint equations are constructed for network elements operating at 330 kV and 132 kV. Limitations on zone substation transformers are not considered.

[29] There are parts of the network that are designed to the N-0 planning criterion, as per the Western Power Technical Rules (https://www.westernpower.com.au/resources-education/technical-documentation/distribution-network-documentation/technical-rules/. These networks will experience the loss of power transfer capability following the loss of a transmission element. These types of considerations are factored into quantification of EUE.

system demand term and a constant term associated with any post-contingent remedial actions are assigned to the RHS.

### 3.2.1 Ratings

Where a transmission network constraint is related to the thermal loading of a transmission network element, the limit has been set applying a 'summer' and 'not-summer' seasonal rating. Summer ratings are applied to all periods in the months from November to March inclusive whilst not-summer ratings are applied to all periods in other months.

Several regions in the SWIS are set to commence operation with dynamic line ratings (DLR). DLR is an online monitoring system that computes ratings for network elements based on local operating conditions for use in market and operational dispatch decisions. These ratings may differ to the design rating, owing to different assumptions used in deriving the design rating at the time of design and commissioning. The intention of DLR is that its implementation will increase the RHS limit of a constraint equation and enable the SWIS to be operated with additional capacity. EY has not implemented DLR due to insufficient information being available at the time of modelling and limitations around forecasting future operating conditions in regional parts of the network.

### 3.2.2 Network reinforcement schemes

Network Reinforcement Schemes that are currently operational in the SWIS are modelled based on information provided by Western Power. These schemes can materially impact transmission network congestion modelling in different SWIS regions and include generator runback/curtailment schemes, load runback/curtailment schemes and operational measures such as opening circuit breakers to reconfigure the network.[30] These schemes allow the transmission network to be operated with higher network utilisation levels and have been factored into the constraint equations through offsets to the limit equation (the RHS), or by modifying coefficients in the flow equation (the LHS).

### 3.2.3 Network states

For the purpose of this reliability assessment, the transmission network constraint equations have been formulated based on a number of projected network 'states', based on information provided by Western Power[31]:

- 2024-25: Existing network
- 2025-26: Ratings upgrade associated with the East Region Stage 1 project[32], also known as East Regional Energy Project (EREP)
- 2026-27: A portion of the full Clean Energy Link - North Region project.
- 2027-28: Clean Energy Link – North Region project.

[30] In certain regions, customers have had to accept a lower level of reliability to connect. For example, customers in the Eastern Goldfields have been connected under the Eastern Goldfields Load Permissive Scheme (ELPS). These customers are curtailed by Western Power when there are very high loadings on the 220 kV line. Whilst individual customer connections are not modelled, quantification of EUE consider that some customers are on ELPS and different planning criterion applied to certain parts of the network.

[31] The earliest date for commissioning the Clean Energy Link project (previously known and referred to as the North Region Energy Project [NREP]) is summer 2027-28. This has been modelled in two states – for 2026-27 and for 2027-28.

[32] See https://www.westernpower.com.au/siteassets/documents/transmission-system-plan-2023-20230929.pdf.

### 3.2.4 Other considerations

Other power system security constraints have been modelled to account for minimum demand thresholds (MDT) and to limit the dispatch from multiple Facilities that may be connected behind a single connection point exceeding declared sent out capacities.

## 3.3 Scope item 3: Assessment against the Planning Criterion

The main objective of scope item 3 is to identify and characterise any capacity or reliability shortfalls for each modelled scenario (which for this year's study is the 10% POE peak demand under the expected demand scenario).

As set out in Section 1, the Planning Criterion is comprised of two components, referred to as Limb A and Limb B. The reliability standard requires there to be sufficient capacity available in the SWIS in each Capacity Year to meet **both** requirements (i.e., both Limb A and Limb B need to be satisfied).

Limb A of the Planning Criterion is made up of four building blocks. The building blocks are presented in Table 3.

**Table 3: Building blocks of Limb A of the Planning Criterion**

| Building block of Limb A | Description |
|---|---|
| **Annual peak demand** | Forecast annual operational sent-out peak demand for 10% POE the expected demand growth scenario. |
| **IL allowance** | Estimate of the capacity required to cover the forecast requirements of Intermittent Loads (ILs), which are excluded from the 10% POE peak demand forecast. |
| **Reserve margin** | Determined as the greater of:<br>► peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages and<br>► The largest contingency relating to loss of supply at the time of peak demand.<br>For the purposes of this WEM ESOO, AEMO has considered that the largest risk to be equivalent to the loss of the three largest energy producing units. |
| **FR allowance** | Accounts for Regulation Raise quantities, escalated to account for the impact of new DPV and large-scale wind and solar capacity. |

To assess the extent to which the AIC of the Energy Producing Systems and DSP capacity is capable of satisfying Limb A of the Planning Criterion, for each modelled scenario and each modelled year we:[33]

► Quantify the Limb A requirement by determining its building blocks.

► Identify AIC as well as associated forecast Reserve Capacity, advised by AEMO.

► Identify years where there is a capacity shortfall by comparing the annual sum of Reserve Capacity of the AIC fleet against the annual requirement set by Limb A.

To assess the extent to which the AIC of the Energy Producing Systems and DSM capacity is capable of satisfying Limb B of the Planning Criterion, for each modelled scenario and each modelled year we:

► Run the 2-4-C model to dispatch the AIC under each scenario and agreed assumptions.

[33] AIC will be determined as existing SWIS installed capacity (generation, storage, DSM) less existing capacity retirements + committed capacity, and will be advised by AEMO.

- ► Identify if there are any years where the Limb B requirement is not met. To do this, we derive the annual EUE percentage indicator (annual EUE %) by dividing modelled annual EUE volumes (MWh) by annual energy consumption (MWh) and compare the results against the 0.0002% standard.
  - ► We use the annual operational energy consumption provided by AEMO as the denominator of this calculation.
  - ► Calculate the EUE % based on averaged results of the multiple reference years and Monte Carlo iterations.

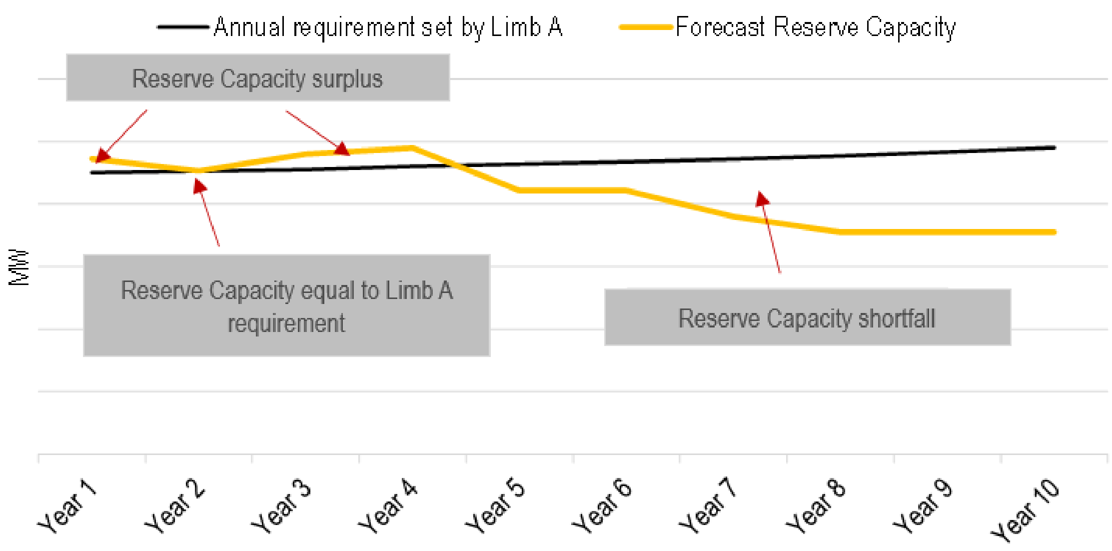
The logic of the assessment against Limb A and Limb B of the Planning Criterion is illustrated below in Table 4. Table 4 provides a summary of the four possible combinations of outcomes from the analysis in scope item 3.

**Table 4: Illustration of the logic of the assessment against Limb A and Limb B of the Planning Criterion**

| Case | Limb A requirement (MW) | AIC (MW) | Reserve Capacity (MW) | Limb A assessment: possible results | Limb B assessment: possible results |
|---|---|---|---|---|---|
| | Based on building blocks | Existing units less retirements + committed units | Advised by AEMO | Reserve Capacity minus Limb A requirement | 2-4-C modelling (dispatch AIC, assess EUE) |
| | [1] | [2] | [3] | [4] = [3] – [1] | [5] |
| **Case A** | 4,500 | 5,800 | 4,700 | Reserve Capacity surplus (+200 MW) | Reliability surplus (annual EUE < 0.0002%) |
| **Case B** | | | | | Capacity investment gap (annual EUE > 0.0002%) |
| **Case C** | | 5,200 | 4,100 | Reserve Capacity shortfall (-400 MW) | Reliability surplus (annual EUE < 0.0002%) |
| **Case D** | | | | | Capacity investment gap (annual EUE > 0.0002%) |

For assessment against Limb A, we then report on the amount of Reserve Capacity surplus or shortfall in meeting the requirement set by Limb A. Illustrative possible results of this assessment are presented in Figure 5.

**Figure 5: Illustration of possible results of the assessment against Limb A of the Planning Criterion[34]**




For assessment against Limb B, the following key metrics are provided:

- Modelled annual EUE (MWh)
- Annual operational consumption as provided by AEMO
- Modelled annual EUE % and any identified capacity shortfall.

As mentioned in Section 1.2, the assessment against Limb B for the purposes of setting the RCT does not include network constraints, but the analysis on regional shortfalls does add network constraints to the modelling. The results reported in the 2024 WEM ESOO reflect the addition of network constraints to the modelling as well as the outcomes of adding generic unconstrained generators to various locations around the SWIS to examine the extent of EUE that occurs in particular regions (that cannot be addressed by generation located elsewhere).

The ESOO report also provides an assessment of the potential network augmentations to relieve some of these shortfalls based on the outcomes of the regional analysis, and the constraint equations that bind in the model. The ESOO report also contains the outcome of a high-level assessment by EY of the different technologies that may contribute to addressing shortfalls, based on the outcomes and learnings from other long-term planning studies of the WEM.

## 3.4 Scope item 4: Forecasting the RCT

The key objective of this scope item is to determine which component of the Planning Criterion (Limb A or Limb B) will set the RCT, where the maximum of either Limb A or Limb B will be the determining factor. Limb A is a mathematically derived requirement based on the building blocks set out in Section 3.3 and is a known quantity from the calculation carried out in scope item 3.

The capacity required to meet Limb B at this stage of the analysis is an unknown quantity, i.e. the modelling in scope item 3 will result in annual EUE being either above or below 0.0002% but not exactly at this threshold. The change to the treatment of 'Capacity for Reliability', 'CFR' in this year's study means a different approach

[34] Figure has no y-axis numbers deliberately as it is for the purpose of illustrating possible outcomes of the comparison between the Limb A requirement and forecast Reserve Capacity only.

to determining the Limb B requirement. Where CFR was completely additional to AIC and did not interact with other capacity in the market, a separate ‘CFR’ tool was ran to solve for the exact MW of capacity that would set EUE to no more than 0.0002%.

However, with the change to CFR now being able to interact with storage and preserve the running hours of DSP, these interactions are required to be modelled through each 1,200 iterations of each future Capacity Year in the dispatch model. The updated process to determining whether Limb A or Limb B sets the requirement is set out as below - noting also that as set out in Section 1, the updated WEM Rules requirements result in a methodology change for the determination of the Limb B required capacity, in that the modelling should now not include thermal network constraints.

► Step 1: Run the dispatch model with the AIC and half-hourly demand profiles to calculate the EUE for each Capacity Year.

► Step 2: Assess the calculated EUE and determine whether re-run is required for each Capacity Year based on the conditions outlined in the table below.

**Table 5 Limb B calculation conditions**

| EUE | Limb B modelled AIC compared to Limb A | Re-run is required |
|---|---|---|
| Less than 0.0002% | Limb B modelled AIC<Limb A requirement | No |
| Less than 0.0002% | Limb B modelled AIC>Limb A requirement | Yes |
| More than 0.0002% | N/A | Yes |

► Step 3: Re-run as required for the relevant Capacity Year by setting Limb B set Limb B capacity to just under the Limb A requirement (by 1MW). If EUE remains below the 0.0002% reliability standard, then Limb A sets the RCT. If EUE exceeds the standard, further modelling is required to establish the Limb B requirement.

The 2024 ESOO report provides the outcomes of each step in the process, illustrated by the results of each step for the 2024 reliability assessment.

## 3.5 Scope item 5: Capability Classes

As set out in Section 1, the WEM Rules have changed the approach to categorising different capacity types since the 2023 reliability assessment. The assessment for this scope must now determine the minimum capacity required to be provided by Capability Class 1 (CC1) and Capability Class 3 (CC3) capacity, and an appropriate mix of additional CC1 and CC3 capacity required if any shortfall is identified for the year in question (2026-27) in the 10% POE expected demand scenario.

The modelling in the reliability study is required to determine the minimum amount of capacity to be provided by Capability Class 1 and Capability Class 3 for 2026-27 (the third years of the Long Term PASA Study Horizon) while limiting EUE to no more than 0.0002% of annual energy consumption.

To provide this, the modelling takes the following steps:

- The WEM Rules require the analysis to take account of the Availability Duration Gap Load Scenario (ADGLS). AEMO provided this half hourly load scenario for each historical weather reference year (using the half-hourly operational demand traces provided by EY, as adjusted by dispatch of ESR and DSP in line with the WEM Rules requirements (in clause 4.5.12(a)). The trace providing the ADGLS is incorporated into EY's model for the Capability Class modelling in accordance to clause 4.5.12(i) of the WEM Rules.

- On the supply side, the first step is to equalise the modelled capacity and associated CRC with the RCT for 2026-27. As CRC is above the RCT in this year (5,742 MW compared to 5,696 MW, respectively) this requires reducing the AIC by 46 MW and re-running to review EUE outcomes.

- In line with the proposed approach, capacity is removed from the model in order of assumed retirement date. Therefore, for the initial step in the modelling, 46 MW is removed from Collie power station. EUE outcomes are observed and if EUE <0.0002% then the modelling can proceed to iteratively add more capacity to Capability Class 2, whilst equally reducing capacity from Capability Class 1 and 3, and observing EUE outcomes until no more Class 2 can be added without breaching the reliability standard.

- Capability Class 2 includes both DSP and ESR technology types. Each of these have different energy supply characteristics, with ESR limited by its ability to charge and the size of its storage resource (e.g. 2 hour, 4 hour and so on) while in 2026-27 DSP is only required to provide a response for up to 50 hours in the year, between the hours of 8am and 8pm.

- Taking a conservative approach, it is assumed that the technology type that reaches the EUE limitation first will set the maximum capacity for Class 2 and therefore the minimum capacity required for Class 1 and Class 3. The modelling confirms that DSP sets this limitation first, given its more restricted running hours than ESR.

- The total for Capability Class 2 is therefore the sum of the CRC for assumed capacity in the modelling for 2026 27 from existing and committed projects, plus the CRC associated with the additional DSP that could be added to the model before the reliability standard was breached.

## 3.6 Scope item 6: Battery round-trip efficiency losses modelling

This scope item involved modelling battery energy storage to forecast the impact of round-trip efficiency losses on operational demand. This involved amending the approach to modelling batteries. The reliability study models batteries to charge when they can (when any other generation is available regardless of price, apart from DSP, which is bid very last to preserve its limited available hours) and then reserves that charge until it is needed to avoid unserved energy.

This is different to typical battery cycling behaviour when generally batteries would be seeking to cycle (charge and discharge) at least once per day to maximise energy price arbitrage opportunities. Therefore the bidding behaviour of batteries was amended for this scope item so that batteries sought to maximise energy price arbitrage and charge and discharge each day, so that the impact on this kind of daily cycling on operational demand can be seen. The algorithm that underpins the strategy applied to storage for this scope item is referred to as ‘residual demand (RD)’. More information on how RD works can be found in B.1.10.

To allow the full impact of battery charging on minimum operational demand levels, the minimum demand threshold was removed from the model. When this is in place it curtails rooftop PV so that demand (which in the modelling usually excludes loads dispatched in the market) does not fall below 500 MW. This was removed for the purpose of the storage modelling.

# Appendix A List of abbreviations

| Abbreviation | Explanation |
|---|---|
| **AC** | alternating current |
| **AEMO** | Australian Energy Market Operator |
| **AIC** | anticipated installed capacity |
| **BTM** | behind-the-meter |
| **CC** | Capacity Credits |
| **CCGT** | combined cycle gas turbine |
| **CER** | Clean Energy Regulator |
| **CER** | Consumer Energy Resources |
| **CFR** | Capacity for Reliability |
| **CONE** | cost of new entrant |
| **CRC** | Certified Reserve Capacity |
| **DC** | direct current |
| **DPV** | distributed PV |
| **DSP** | Demand Side Programme |
| **EREP** | East Region Energy Project |
| **ESM** | Emergency Solar Management |
| **ESOO** | Electricity Statement of Opportunities |
| **ESR** | Electric Storage Resources |
| **ESROI** | Electric Storage Resource Obligation Intervals |
| **ESS** | Essential System Services |
| **EUE** | Expected unserved energy |
| **EV** | electric vehicle |
| **FIR** | Formal Information Request |
| **FR** | Frequency Regulation |
| **FRC** | Forecast Reserve Capacity |
| **FSC** | fixed shape consumption |
| **HILP** | high impact, low probability |
| **Hz** | hertz |
| **IL** | Intermittent Load |
| **kW** | kilowatt |
| **LFAS** | Load Following Ancillary Service |
| **LHS** | left hand side (of constraint equation) |
| **LIL** | Large Industrial Load |
| **LMT** | EY's Load Modelling Tool |
| **LRR** | Load Rejection Reserve |
| **Long Term PASA** | Long Term Projected Assessment of System Adequacy |
| **MDT** | Minimum Demand Threshold |
| **MW** | megawatt |
| **MWh** | megawatt hour |
| **NAQ** | Network Access Quantity |
| **NEM** | National Electricity Market (Australia's East Coast) |

| Abbreviation | Explanation |
|---|---|
| **NOFB** | Normal Operating Frequency Band |
| **NOFEB** | Normal Operating Frequency Excursion Band |
| **NREL** | National Renewable Energy Laboratory |
| **NREP** | North Region Energy Project |
| **OCGT** | open cycle gas turbine |
| **OPSO** | operational sent out |
| **POE** | Probability of Exceedance |
| **PVNSG** | photovoltaic non-scheduled generator |
| **RCM** | Reserve Capacity Mechanism |
| **RCT** | Reserve Capacity Target |
| **RHS** | right hand side (of constraint equation) |
| **SAM** | System Advisory Model |
| **SEST** | EY's Solar Energy Simulation Tool |
| **SRAS** | Spinning Reserve Ancillary Service |
| **SRMC** | short-run marginal cost |
| **SWIS** | South West Interconnected System |
| **V2G** | vehicle-to-grid |
| **VPP** | virtual power plant |
| **WA** | Western Australia |
| **WEM** | Wholesale Electricity Market (Western Australia) |
| **WEMDE** | WEM Dispatch Engine |
| **WEST** | EY's Wind Energy Simulation Tool |

# Appendix B Modelling methodology

This appendix provides an overview of the modelling approaches that are unchanged from the 2023 reliability assessment.

## B.1 Assumptions relating to generation, storage and demand-side response providers

AEMO has provided EY with the generation, storage and demand side capacity that is expected to be participating in the WEM over the study period. This includes assumptions around which Facilities may enter the market and those that have been announced or are assumed to exit the market. For the purposes of modelling, and categorising how the modelling treats each of these Facilities, the various types of Facilities modelled are described as follows:

- Thermal generators (coal, gas, diesel, waste-to-energy, landfill gas)
- Intermittent generators (wind and solar)
- ESR
- DSP

Table 6 sets out the key characteristics that impact a Facility's interval-to-interval availability to meet the demand for energy in the SWIS, captured within EY's modelling. Additional assumptions that are specific to each Facility type are discussed in each section below as relevant.

**Table 6: Key characteristics modelled for all Facilities**

| Assumption | Source | Notes |
|---|---|---|
| **Planned maintenance** | Advised by AEMO/FIR data, plus EY modelling as required.* | Further detail in Section B.1.6 |
| **Forced outage rates** | Advised by AEMO/FIR data, plus EY modelling as required.* | Further detail in Section B.1.7 |
| **Fuel type** | AEMO market data/advised by AEMO for new Facilities. | The capacity of gas pipeline infrastructure is not modelled. |
| **Maximum sent out capacity** | Advised by AEMO/FIR data.* | |
| **Ramp rates by Facility (up/down)** | AEMO market data/advised by AEMO for new Facilities. | Defined as MW/minute, up/down capability. |
| **Capacity Credits and forecast Reserve Capacity by Facility** | Advised by AEMO. | |
| **ESS capability** | Advised by AEMO. | Contingency Reserve Raise and Regulation Raise services. |
| **Energy market bids** | Merit order agreed with AEMO | For the reliability study the precise bids of each unit are of secondary importance, as at times of high demand all available Facilities will be dispatched regardless of their market bid.<br>The order of bids however and the times of the day during which particular capacity bids in the model is important for energy-limited resources – for example DSP is bid last as it has the most limited annual availability (50 hours per year from 2026-27).<br>Also note that Facilities with NCESS contracts with AEMO are only required to be available over an agreed set of intervals each day, and are bid in the model to reflect this – see further details below. |
| Note: AEMO market data for the WEM can be found here: AEMO \| Market data. | | |

| Assumption | Source | Notes |
|---|---|---|
| *FIR (formal information request) data refers to the data collected by AEMO from Rule Participants as provided for in the WEM Rules as part of the reliability assessment for the Long Term PASA Study Horizon. | | |

### B.1.1 Thermal generators

The key assumptions relating to thermal generators for the purposes of the reliability study refer to their maximum sent out capacities, ramp rates, planned maintenance schedules and unplanned / forced outage characteristics.[35] Each Facility is modelled individually and is dispatched fully as required to meet projected demand in each interval, subject to its maximum sent out capacity in that interval, maintenance and forced outages and any network or other constraints (e.g., ramp rates) on its output.

Thermal generators are bid into the market model based on a set of input bids constructed in price quantity pairs that are benchmarked by EY to recent WEM price and generation outcomes.[36] We note that at times where unserved energy may present, we expect every available Facility to be generating at its maximum available capacity (subject to outages, ramp rates, ESS headroom, impact of network constraints) to avoid unserved energy, which means that the bids and the position of a Facility in the bid merit order (BMO) will be of secondary importance.

### B.1.2 Large-scale energy storage modelling

In the WEM, large-scale storage that is assigned Capacity Credits is required to be available for a set of eight contiguous 30-minute Trading Intervals. These are set by AEMO and make up the Electric Storage Resource Obligation Intervals (ESROI) in the WEM Rules.

The reliability assessment includes existing and committed large-scale storage units. For the main scope items of the reliability study, EY has modelled storage with priority on generating during periods where there is a heightened risk of unserved energy (noting that the scope item of battery losses modelling takes a different approach as set out in Section 3.6). This requires prioritising charging the storage unit at all other times. We note that this does not automatically align exactly with the ESROIs as described above.

There may well be risk of unserved energy outside of ESROIs, e.g., 15:00 to 16:00 on a cloudy, low-wind afternoon with low thermal generator availability during the spring season. Considering this example, for the purpose of the reliability assessment we have modelled the operation of large-scale storage to ensure unserved energy is avoided whenever possible. This means that storage units may operate outside of the ESROI intervals and not be at a full state of charge at the beginning of the ESROI interval. This approach was agreed with AEMO on the basis that if risk of unserved energy was known in advance the ESROI intervals may be revised on an operational timeframe in consultation with ESR providers.

### B.1.3 Modelling of intermittent generators

To model large-scale wind and solar Facilities, EY models future half-hourly generation availability profiles based on historical wind and solar resource data for various locations. These availability profiles reflect potential renewable energy output (in MW) before the impact of network curtailment (due to thermal limits of network equipment) or economic spill.[37] The reliability study incorporates 12 historical weather reference year data from FY 2010-11 to 2021-22 to ensure a spread of different weather patterns are considered when

[35] For non-intermittent generators, 24C uses the CRC level to define the maximum dispatchable capacity when the unit is fully available.
[36] The benchmarking process is carried out every 6-12 months and creates a range of input bids that are set up in price quantity pairs that aim to yield outcomes that align with the latest market outcomes The most recent bids are aligned with a full benchmark carried out on the 2022-23 financial year. As mentioned above however the actual value of bids are of secondary importance in a reliability study.
[37] Economic spill relates to the scenario where interval demand is such that available wind and solar resource is not fully utilised. In such cases, generation bidding into the market at lower (or equal) prices than the unused wind and solar availability is sufficient to meet demand, and the unused availability of wind or solar is “spilled”, i.e., not dispatched.

forecasting supply reliability.[38] This is particularly important as the WEM transitions to increasing proportions of intermittent generation sources.

An overview of our methodology for wind and solar modelling is as follows:

- **Wind**: EY's half-hourly wind generation modelling is based on location-specific historical wind resource data.
    - The first step involves collection of historical hourly short-term wind forecast data (wind speed and direction forecasts from a few hours ahead) from the Bureau of Meteorology (the Bureau) for a 12 km grid across the relevant areas of WA.
    - EY's Wind Energy Simulation Tool (WEST) is then used to develop half-hourly, time sequential, locational wind availability profiles for existing and potential wind farms used in the modelling. WEST does this by scaling the wind speed data for each site and processing through a typical wind farm power curve to target a specific annual capacity factor. The scaling is usually required to convert the modelled wind speed to the representative wind speed received by the wind farm.
    - The capacity factor target for each wind farm (existing and committed) is based on market observations and estimations (noting that published data on wind farm *availability* is not available for the WEM – the published data on wind farm output is actual dispatched generation which will be availability net of economic spill and/or generation curtailed due to constraints and/or operational actions used by AEMO to manage power system security).[39]
- **Solar PV**: Similar to wind modelling, the large-scale PV half-hourly availability profiles produced by EY are based on historical data collected from the Australian Bureau of Meteorology, processed by EY to convert the resource to develop half-hourly, time-sequential, locational solar PV generation availability profiles.
    - The data collected is historical satellite-derived solar insolation data, with hourly data on a 5 km grid for 2010-11 to 2015-16 and 10-minute data on a 1 km grid for 2016-17 onwards. The solar insolation data is combined with weather station data of temperature and wind speed from the Bureau to account for impacts of those variables on solar cell efficiency.
    - EY applies its Solar Energy Simulation Tool (SEST), which uses the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to convert the resource data to generation availability profiles for each Facility (targeting an annual capacity factor or using EY's calibrated settings to predict the capacity factor for a given solar farm design).
    - Modelled annual available capacity factors may vary from site to site as a result of calibration to the performance of existing solar farms and the locational resource data as well as assumed design characteristics such as solar position tracking and the DC capacity to AC capacity ratio. [40]

For both wind and solar, the capacity factor may vary between historical weather reference years based on inter-annual differences in the underlying locational resource data.

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[38] These reference years reflect the data that was available and processed through EY's processes and rigorous quality checks at the time of the study. Regardless of the weather reference year applied, each is adjusted to match the peak demand and annual operational consumption as forecast by AEMO for each Capacity Year.

[39] Annual capacity factor targets to inform creation of half-hourly wind resource availability profiles were obtained through EY's analysis of the Global Wind Atlas data as well as observed half-hourly generation output data for WEM wind farms throughout historical weather reference years. EY has also considered industry feedback received through planning processes such as the WA Whole of System Plan and the SWIS Demand Assessment to estimate the capacity factors for new entrants.

[40] Annual capacity factor targets to inform creation of half-hourly wind resource availability profiles were obtained from observed half-hourly generation output data for WEM solar PV farms throughout historical weather reference years. EY has also considered industry feedback received through planning processes such as the WA Whole of System Plan and the SWIS Demand Assessment to estimate the capacity factors for new entrants.

As noted in Section B.1.6, where information is available on planned maintenance periods for intermittent generators, we have included this in the modelling (i.e., modelled it as unavailable during the stated Trading Intervals in future). As noted in B.1.6, the nature of outages for wind and solar generators is different from large thermal generating units due to the modular nature of wind turbines or solar panels within a Facility. The capacity factors modelled for wind and solar farms are based on observed and/or expected output of the wind and solar farms modelled, and as such implicitly include the impact of planned and forced outages (which are expected to impact only a subset of turbines or panels at any given time).

### B.1.4 Demand-side providers

Demand-side response providers have been included in the dispatch modelling based on information provided by AEMO. These providers typically operate as last-resort capacity suppliers to the energy market and as such, have been bid to be dispatched last in the BMO. The modelling applies the same bid to each of these units meaning that all will be dispatched simultaneously in the model if required (up to their annual availability as described below), with tie-breaking enabled in the model to share dispatch across each provider. In real-time dispatch, AEMO forecasts a need for DSM and activates DSP Facilities ahead of the relevant Dispatch Interval (which would be expected to be at Maximum STEM Price but might not be). As such, all DSP Facilities have the same merit.

Demand side response providers in the WEM are required to satisfy minimum availability requirements according to the WEM Rules. Each demand-side response provider has been modelled according to the parameters provided on:

- Maximum annual available hours of demand-side response.
- Maximum MW demand-side response provided per event.
- Maximum number of response events per year and maximum number of hours per day duration.
- Minimum number of hours response provided.
- Availability for demand-side response, including business / non-business day and time of day.
- Ramp rates.
- Any other availability constraints as advised by AEMO.

### B.1.5 NCESS Facilities

The capacity procurement undertaken by AEMO as described in Section 1.3, has resulted in a number of Facilities in the WEM with contracts with AEMO to provide the NCESS Peak Demand service. Under these contracts, these Facilities, or the capacity of those Facilities associated with the contract is required to be available every day during the ESROI periods.

For the 2024 reliability study, the ESROI intervals were applied as follows, based on an interim assessment of the Peak Demand period and an indicative assessment of ESROIs available at the time of modelling:

- Summer (December to March): 16.30 to 20.30
- Winter (June to August): 17.00 to 21.00
- Shoulder (all other months): 16.30 to 20.30

Storage Facilities continue to be dispatched to avoid EUE but otherwise NCESS Facilities are bid into the model only during the ESROI intervals and are bid very last in the merit order, reflecting that these Facilities would be called upon as a last resort.

### B.1.6 Planned maintenance

AEMO has provided EY with data collected through its formal information request (FIR) process which includes the planned outage data provided by market participants, including the start and end intervals of the outage and MW of capacity on outage (i.e., either full or partial outages).

As noted in the FIR file from AEMO, not all Facilities provided planned outage information where schedules are not yet available. In some instances, we noted that maintenance is planned up to a certain point in time (e.g., to 2026-27) but not for the full modelling period required for scope items 1 and 2 of this reliability assessment.

The following approach has been undertaken to model planned maintenance:

- ► Where maintenance schedules are provided for the full modelling period (i.e., up to 2033-34), EY has implemented these directly into the dispatch model.

- ► Where maintenance schedules are provided only up to a certain point, EY has used its maintenance scheduling tool (the Maintenance Creator) to schedule maintenance for the years where data is not available (further detail below).

- ► Where maintenance schedules are not available but guidance has been provided in the FIR (e.g. number of hours planned per year), this information has been incorporated into EY's Maintenance Creator and used to schedule maintenance (e.g. for the indicated number of hours per year).

- ► Where no data is available (i.e., neither dates nor length of maintenance), we have agreed technology specific maintenance parameters that are applied to each Facility with AEMO (i.e., on number of hours / days of maintenance per year) and have applied these through our Maintenance Creator to schedule maintenance for these units (see Section D.7 in 0).

EY's Maintenance Creator tool schedules maintenance for each Facility in the 2-4-C model during periods estimated to typically have low demand for a given number of days each year generally depending on technology (or Facility-specific) assumptions. The tool starts with the largest Facility and the largest number of maintenance days blocks first and continues to identify the next lowest demand periods to schedule maintenance days for the next Facility in order of their MW capacity.

The Maintenance Creator has been provided with scheduled maintenance dates as submitted to AEMO via the FIR data. The tool has taken those planned periods into account and scheduled maintenance for other units around those periods. By allocating planned maintenance to the largest units first, the tool has ensured they are put on maintenance during the lowest demand periods, considering the number of days they are required to be on maintenance. The ultimate date chosen is the date which has the lowest demand period throughout the maintenance duration, not necessarily the lowest demand day.

The Maintenance Creator tool iterates through all Facilities from largest to smallest, checking if there is a planned maintenance already input for that year, checking if other units in that Facility are already on maintenance (and if so, skip to the next Facility) and checking if any other restrictions have been added (e.g., it can be set to not allow maintenance over a set of defined months such as the summer months). This process continues until all Facilities have been assigned planned maintenance schedules for each year of the study.[41]

It is noted that in reality, AEMO must assess Outage Plans against the criteria for evaluating Outage Plans set out in Clause 3.18E.8 of the WEM Rules (the Outage Evaluation Criteria are met when in AEMO's opinion there will be sufficient Network in service and capacity, including DSP capacity to maintain Power System Security and Power System Reliability). For modelling purposes these criteria were not specifically applied to the maintenance scheduling, however due to the way in which the tool schedules maintenance (by allocating the

[41] EY has assessed whether scheduled maintenance across the fleet contributes to the EUE. In a power system with insufficient supply capacity across the majority of the year rescheduling maintenance has negligible impact except for moving the observed EUE to another period of time.

largest units to the lowest demand periods and iterating through units by size) there is likely not a more optimal time to arrange maintenance from a supply-demand balance perspective.

### B.1.7 Forced outages

The modelling of each future year of this reliability assessment includes multiple iterations of forced outages to capture a range of potential outage outcomes that may occur at the half-hourly level for the same modelled interval. One of the key drivers of uncertainty of outcomes is the probabilistic nature of forced outages (they are unplanned and can occur randomly at any time due to a whole range of potential causes).

For this reliability study, 2-4-C was applied to simulate a large number of Monte Carlo iterations to capture the impact of forced (unplanned) outages on the availability of the supply side to meet prevailing interval demand. [42]

Each Monte Carlo iteration assigns random outages to each generating or storage Facility, based on assumed outage statistics. These statistics have been provided by AEMO and are based on outage data from 10 February 2021 to 10 February 2024

A 'mean time to repair' and a 'mean time to fail' value of hours is assigned to each Facility in the simulation. A Facility on a forced outage is excluded from the BMO and is unable to be dispatched to meet demand in that interval (or in the case of a partial outage, a proportion of the Facility's capacity is modelled as unavailable).

As noted in Section B.1.3, the nature of forced outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a Facility. The capacity factors modelled for wind and solar Facilities are based on observed and expected output of the wind and solar Facilities included in the modelling, and as such implicitly include the overall impact of outages on a Facility's availability.

### B.1.8 Ramp rates

The ability of a Facility to contribute to meeting energy demand (or provide ESS) can depend on how quickly it can increase or decrease its output. For 30-minute modelling ramp rates may not bind often but for the purpose of a reliability study it is particularly important to capture the ability of generators (and demand-side response providers) to ramp up (or down) to the required level from one interval to the next.

Data on generator ramp rates is sourced from the publicly available data on WEM Facilities on AEMO's website.[43] These are input into the 2-4-C database and the assumed rate of MW/min for ramping up and down will be taken into account in the modelled dispatch of each Facility.

### B.1.9 ESS bidding

The Regulation Raise and Contingency Reserve Raise have been modelled with Facilities cleared for each of these markets based on bid profiles into these markets. Facilities are cleared based on a co-optimised merit order considering bids across all ESS markets and the energy market.

An ESS bid curve was produced for each Facility that is eligible to participate in the different ESS markets. For the purposes of the reliability assessment, these bid curves were simplified to ensure that facilities eligible for ESS would meet ESS requirements ahead of participating in the energy market.

[42] For each of the Capacity Years of the reliability assessment, EY modelled a population of 1,200 Monte Carlo iterations. An assessment in the 2023 study on the basis of the coefficient of variation for the 2025-26 Capacity Year indicated that the modelling achieved convergence (i.e. a stable value of the coefficient of variation) meaning that increasing the population of Monte Carlo simulations would not significantly change the modelled EUE outcomes. Such assessment is e.g., exercised by the European Network of Transmission System Operators for Electricity (ENTSO-E) in the European Resource Adequacy Assessment for the European Union interconnected electricity system. The selected number of Monte Carlo also maintained simulation speed (model runtime) within reasonable timeframes.
[43] AEMO | Data (WEM)

### B.1.10 Residual demand approach to battery energy storage modelling

This section describes the forward planning approach used by short-duration storage in EY's modelling of batteries for scope item 6 (round-trip efficiency losses estimation).

EY's short-duration storage planning methodology is applied daily throughout each simulated year. It is based on developing an imperfect forecast of the wholesale market prices for the next two days and planning an optimal charging and discharging profile over those two days to maximise wholesale market price arbitrage. The strategies developed take into account the parameters of each specific battery including the present state of charge, available storage capacity and the round-trip efficiency.

The imperfect price forecast is based on residual demand, which is equal to operational demand minus the available large-scale wind and solar generation and other low bidding generation. The strategy develops a relationship between residual demand and prices over the previously simulated four days, and then uses this relationship to forecast the price for the next two days to feed into the battery charge and discharge decisions. The price forecast uses a perfect forecast of residual demand for those next two days (which is known by the model as half-hourly demand, wind and solar generation are inputs into the model).

However, the price forecast is imperfect since it does not take into account any curtailment of wind and solar generation and does not foresee any changes to generator availability. The optimal battery charge and discharge profiles determined by the strategy consider the impact the battery's charging and discharging may have on the price, effectively considering that the battery's charge or discharge would change the residual demand.

Once the battery charge and discharge profiles are determined, these are fixed for 24 hours of time-sequential modelling, and the discharge profile is bid at approximately $0/MWh. Any remaining discharge capacity over and above the discharge profile is effectively bid at higher bid bands such that the battery will discharge at its maximum discharge capacity to capture attractive revenue opportunities in the market, as long as there is storage capacity available. The residual demand strategy is then reset taking in the previously simulated four days (a moving window of four days) and determining a new charge and discharge profile for the following two days.

# Appendix C Modelling half hourly demand

## C.1 Introduction

This section describes the principles and steps used by EY to produce half-hourly demand data inputs based on AEMO's forecasts of peak demand (MW) and annual energy (MWh) for the 2024 WEM ESOO. Half-hourly demand data was used as inputs to the 2-4-C model used in the reliability assessment for each future year and scenario.

- Section C.2 describes the use of historical weather reference years, which is EY's approach to capturing the potential future variation in time-sequential, per-interval demand as well as renewable resource availability.
- Section C.3 sets out the annual forecasts provided by AEMO (most of which are typically published each year in the WEM ESOO).
- Section C.4 describes the steps EY has taken to convert the annual (or monthly) forecast data provided by AEMO into half-hourly demand profiles and renewable resource availability profiles used in the modelling.

## C.2 Approach to forecast years based on historical weather reference years

EY's approach to forward-looking half-hourly modelling is to base all the intertemporal and interspatial patterns in electricity demand, wind energy and solar energy on the weather resources and consumption behaviour in one or more historical years (referred to as reference years).

This helps to retain the relationships between time of day, consumption behaviour and renewable resources. We consider this an essential aspect of modelling supply reliability, and allows our model to capture high impact, low probability (HILP) events induced by weather conditions and demand variability.

We believe that retaining correlation (or temporal synchronisation) between demand and renewable resource data is fundamental to assessing the reliability / operability of power systems, particularly with increasing penetration of wind and solar generation.

The key principles of this approach are as follows:

- The historically observed inter-temporal and inter-spatial impact of weather patterns are maintained in the forward-looking dataset. Historical hourly locational wind and solar resource data is used by EY to model half-hourly generation from rooftop PV, large-scale solar PV and wind generation (see also Section B.1.3). All the correlated interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather patterns.
- Intertemporal and inter-spatial (regional) electricity consumption behaviour is maintained in the forecast. Historical half-hourly grid demand is obtained from AEMO. We then add EY's historical modelled rooftop PV generation output to produce the historical electricity consumption. By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation and how that is changing the half-hour to half-hour shape of grid demand during each day. EY also separately models behind-the-meter storage profiles and electric vehicle charging profiles to capture their impact on the shape of grid demand.
- The historical years used in the modelling consist of various types of weather, which may or may not be considered typical or average. For the purposes of this reliability study, the 10% POE expected demand scenario is used to deliver the reliability study scope items although demand traces for all scenarios (the 10% POE and 50% POE for low, expected and high demand) have been developed as part of scope item 1.

- Overall, the half-hourly modelling methodology ensures that the underlying weather patterns and atmospheric conditions are projected in the forecast, capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in a historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The availability of renewable generation which is assumed to be operational within a given period is a function of the atmospheric conditions specific to each plant location and as would have been experienced across the whole SWIS during the same weather event.

- As a final step, based on advice from AEMO, the half-hourly demand profiles across different weather years underwent a final adjustment so that overall, on average, the operational peak aligned with AEMO’s estimate of operational peak in each year.

## C.3 Inputs to half-hourly demand modelling

The demand scenarios modelled in the reliability assessment are consistent with the 2024 WEM ESOO scenarios. AEMO provided the demand inputs as set out in Table 7 on an annual (or in some cases seasonal or monthly) basis. Based on AEMO's forecasts, EY developed half-hourly projections covering every Trading Interval in the forecast period and used these half-hourly projections in dispatch modelling.

**Table 7: Annual demand and CER inputs from AEMO**

| Item | Units/coverage | Notes |
|---|---|---|
| **Annual underlying peak demand** | Summer and winter, MW | Not published as part of WEM ESOO, received separately from AEMO in previous years.<br>Ultimately, we calculate/estimate the fixed-shape consumption (FSC) seasonal peak demands (see note in this table, and FSC is defined in Section C.4) and other components separately. These then sum to operational demand (which is an outcome of the demand process). |
| **Annual operational energy** | GWh | We calculate the FSC annual energy demand but use this information to check the final operational demand produced by EY after accounting for each of the various demand components aligns with AEMO's projections. We carry out any post-processing adjustment to align the average peak across the 12 weather reference years with AEMO's. |
| **Behind-the-meter (BTM) rooftop PV** | MW installed capacity and expected energy (GWh) | EY produced rooftop PV profiles that meet the projected energy in each future year before any potential rooftop PV curtailment is applied to meeting minimum operational demand threshold requirements (see Section C.5.1). |
| **PVNSG (small PV non-scheduled generators)** | MW installed capacity and expected energy (GWh) | As above for rooftop PV, except that these are not subject to curtailment as part of the minimum demand threshold. |
| **Electric vehicles (EVs)** | GWh annual consumption from EVs, broken down by EV types with static demand profiles<br>EV virtual power plant (VPP) proportion of total EV demand | EY used data provided by AEMO on monthly uptake of EVs by charging type, vehicle type and typical charging half-hourly profiles and used these to produce aggregate half-hourly profiles for the EV fleet for each year of the study.<br>AEMO provided the proportion of EV VPP (which applied in the expected and high scenarios and represents the charging that is participating in an aggregated virtual power plant arrangement) and EY processed this energy demand through an EV VPP tool (which essentially moves charging from peak demand times to the lowest demand times). VPP assumptions can be found in 0.<br>Vehicle-to-grid modelling was included based on an uptake trajectory provided by AEMO. To reflect the capability of these EVs to both charge and discharge, these EVs were modelled as 5-hr batteries. The dispatch of these batteries was modelled dynamically in the model, similarly to other large-scale batteries. |
| **EV contribution to peak** | MW, summer and winter | The interval time-stamp of peaks for each year and scenario were used to derive this from the half-hourly profiles created as described above. |

| Item | Units/coverage | Notes |
|---|---|---|
| **BTM battery storage** | MW/MWh capacity by year<br>Assumptions on coincident generation, charging and storage capacity utilised<br>VPP proportion of total BTM storage capacity | Based on the annual uptake provided by AEMO, EY created a set of 'static' behind-the-meter storage charge and discharge profiles (for summer and not-summer). These profiles are developed based on an assumption that tariffs are in place that incentivise a reduction in peak demand and charging during low demand intervals during the day. To incorporate imperfection into the aggregated profile of the batteries, the following factors are applied:<br>► **Total energy charge discount**: To account for the likelihood that battery owners won't fully charge their batteries every day the daily charge is limited to 50 percent of the total installed energy capacity.<br>► **Co-incident charge/discharge factor**: This factor accounts for faults, co-ordination and the potential for different tariff signals to lead to batteries never being charged or discharged all the same time. The maximum charge or discharge is limited to 25 percent of the total charge/discharge capacity in MW.<br>Additionally, AEMO provided annual estimates of the proportion of storage that is forecast to participate in a VPP. As it is assumed this capacity is operating as an aggregated and co-ordinated resource, it is operated in the model with the same methodology as applied to large-scale storage. VPP assumptions can be found in 0. |
| **Block loads** | GWh / MW at peak | Modelled with the contribution to peak demand as advised by AEMO and energy aligned with AEMO's projections over the year as a whole. |
| **Electrification** | GWh | Electrification was modelled as a flat, non-flexible 'baseload' demand, based on the MW associated with the projected annual GWh energy demand. |
| **Hydrogen load** | GWh / MW at peak | The operational demand peaks provided by AEMO for the reliability study reflect hydrogen load turning down to ten per cent of its installed capacity at peak times. As a simplified approach, the modelling this year for the reliability study (expected scenario POE10) included hydrogen load at this ten per cent over 4.30 to 9.30pm, and at a higher level nearer its full installed capacity over the year such that the full annual energy consumption is included in the modelling. As explained in Section 2.2.3 this increases the reported EUE but does not impact the Limb B outcomes.<br>The low demand traces published alongside the ESOO also reflect this approach for hydrogen, however for the high scenario hydrogen demand was modelled as a flat 10 per cent load. Given the extent of hydrogen uptake in the high scenario the simplified assumption made to capture energy over the year for the reliability assessment modelling was not deemed appropriate for the high scenario. It should be noted that if referring to the published half-hourly trace for the high demand scenario there is additional load from hydrogen electrolysers that would occur throughout the year, reflecting the forecast annual energy consumption. |

## C.4 High-level overview of approach to modelling demand components

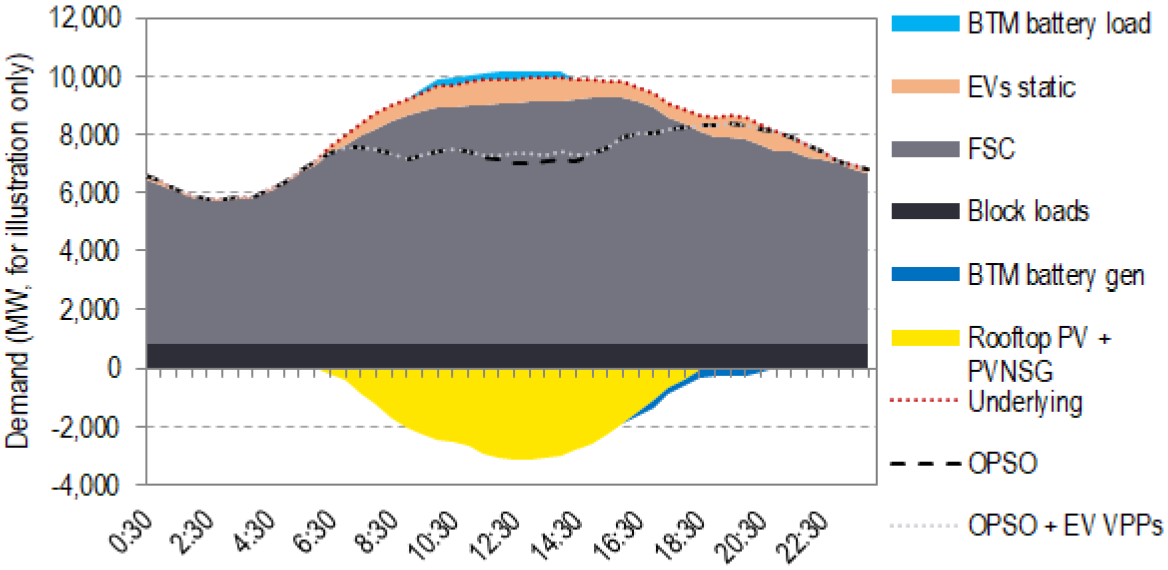
EY's demand modelling philosophy is based on splitting the operational demand into components that can be modelled separately, where each has an influence on changing the shape of the demand profile. These components include:

- BTM rooftop PV generation and small non-scheduled PV generation (PVNSG).
- Electric vehicles (EVs).
- BTM batteries (can have a positive and negative demand at different times).
- Block loads (large flat loads or large industrial loads), hydrogen production loads, and electrification load.

After separating these components in the demand modelling, we consider the remaining demand profile to be of a fixed shape (named 'fixed shape consumption', or FSC), with the shape driven by residential and business energy use behaviour patterns in response to the weather from half-hour to half-hour. We consider these patterns to be fixed across future years, modified for future energy and demand forecasts. We assume that the same temperature and weather conditions in a forward-looking year based on a particular reference year elicits the same demand behaviour as in the corresponding reference year (further detail below).

Figure 6 presents the various demand components that EY models separately, and illustrates how these result in the sent-out operational demand that SWIS Facilities will be dispatched to meet in the half-hourly dispatch modelling.

**Figure 6: Illustrative profile of demand components**[44]




***Notes: FSC – fixed shape consumption, OPSO – operational demand sent-out, VPP – virtual power plant***

At a high level, the approach to producing each of the half-hourly profiles for each component of demand involves the following steps:

- Determine the half-hourly historical operational demand (from market data published by AEMO)
- Determine the historical rooftop PV and PVNSG capacity factors based on monthly data on installed capacity and generation from AEMO and produce half-hourly historical profiles using EY's SEST tool
- Create a historical half-hourly FSC profile for each historical weather reference year.

To create an FSC profile for each forecast year, the annual underlying and operational peak demands (summer and winter, as provided by AEMO) as well as annual operational consumption are processed by EY's Load Modelling Tool (LMT), along with other annual inputs on demand components and CER uptake (as outlined in Table 7 above).

By projecting forward consumption (derived as per the above steps) instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half-hour to half-hour shape of grid demand during each day.

[44] Note that this chart is illustrative only, intended to show how 'Fixed Shape Consumption' is modelled relative to other demand components – the modelling for the reliability study (or any other modelling) may include additional demand components (i.e. hydrogen load, which was modelled as set out in Table 7), or exclude certain of these (i.e. the low demand scenario did not include EV VPP take-up for example).

EY also separately models behind-the-meter (domestic) storage profiles and EV charging profiles to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast by AEMO.

This approach considers that the underlying consumption / FSC peak demand is consistent across different weather reference years (i.e., it is about how high electricity consumption will go in a given year, and is independent of the intra- and inter-day weather patterns that we get from the reference year data). Therefore, based on the underlying peak demand provided by AEMO we have derived a target for the FSC peak demand that is also the same in each reference year for each future year. Due to the varying weather pattern in each reference year we observe differences in the shape of rooftop PV and PVNSG output in different reference years, resulting in different operational peak demands depending on the weather reference year. However, as noted above, the average operational peak over the 12 reference years modelled is aligned with the operational peak provided by AEMO.

## C.5 Behind-the-meter rooftop PV and PVNSG (DPV)

For each scenario of the reliability study, AEMO provided EY with monthly uptake (MW) of distributed PV (DPV), comprising:

- Business and residential behind-the-meter rooftop PV
- PV non-scheduled generators (PVNSG, systems that are greater than 100 kW but smaller than 10 MW generators).

To model BTM rooftop PV and PVNSG, EY uses a similar approach to that for large-scale solar described in Section B.1.3. We use historical data on solar resource at selected locations of the SWIS to estimate historical reference year PV generation and use this to produce half-hourly reference year availability traces for behind-the-meter rooftop PV and PVNSG.

We used the data on degraded MW of capacity provided by AEMO, and capacity factors based on historical monthly data on PV generation and installed capacity provided by AEMO to align with the future PV annual energy forecast provided by AEMO. This historical capacity factor can be used in modelling projections in two ways:

- The same annual capacity factor can be targeted for every reference year profile, or
- The annual capacity factor can be allowed to vary from year to year, but average to the target capacity when considered over all reference years (with the latter allowing more of the natural variability in different weather reference years to be captured within the reliability study).

It was agreed with AEMO to apply the second approach described above (varying capacity factors each year). The half-hourly PV profiles for each year are input into 2-4-C, with generation impacting the operational demand to be met from large-scale generators, storage and demand-side response providers units in each interval. In most intervals, modelled generation of DPV will equal its resource availability profile, however in certain instances DPV may be subject to Emergency Solar Management (ESM) where it will be dispatched below its availability.

### C.5.1 Emergency Solar Management and DPV curtailment

The WA Government's 'Low Load Project – Stage 1 Report' identifies a minimum demand threshold (MDT) of between 550 MW and 650 MW for the SWIS. The MDT refers to the minimum operational demand level below which the SWIS is no longer secure and emergency actions are required.

As part of the response to managing low load conditions in the SWIS, new measures were introduced in February 2022 requiring all new and upgraded behind-the-meter solar PV and battery installations with inverter capacity of 5 kW or less to be capable of being remotely turned down or switched off in emergency situations.

To reflect the above, our modelling implements a constraint that curtails DPV generation if SWIS operational demand were to fall below a particular threshold. For the purposes of this study, AEMO has advised an MDT of 500 MW.[45] As noted in Section 3.6, for the purposes of the battery losses modelling, in order to report on the impact of battery load on minimum demand levels, specifically for that scope item the minimum demand threshold was removed.

## C.6 Electric vehicles (EVs)

AEMO provided EY with detailed information that allowed EY to calculate an aggregate interval-by-interval charging profile for the fleet of vehicles that will charge from the grid, for each scenario and each year of the reliability study.

This information includes a monthly uptake of electric vehicles by vehicle type (10 vehicle types) as well as sample weekday and weekend charging profile for each of these vehicle types by charging profile type (unscheduled / incentivised by time of use tariffs / public and fast charging for example).[46]

Based on the proportion of vehicle numbers undertaking each charging behaviour, we used the monthly uptake to multiply the sample weekday and weekend charging profiles to create an aggregated half-hourly MW electricity demand for the entire fleet.

AEMO also provided the proportion each charging profile assumed to participate in a virtual power plant (VPP) arrangement. Based on that assumption EY modelled the associated energy consumption using its EV VPP tool.

For the VPP component of EVs, rather than applying a 'static' approach to charging, the VPP tool considers demand across each day in the modelled year and selects periods of charging at times which fill in the deepest troughs in demand (and reduces charging at times when demand is higher, or DPV generation has reduced for example).

Note that while the 'static' EV profile is assumed to be the same in each reference year (i.e. it is not driven by differences in weather conditions), the VPP outcomes are determined separately for each weather reference year, depending on the shape of demand in each day of the forecast.

Vehicle-to-grid modelling was included based on an uptake trajectory provided by AEMO. To reflect the capability of these EVs to both charge and discharge, these EVs were modelled as 5-hr batteries. The dispatch of these batteries was modelled dynamically in the model (similar to other large-scale batteries) and operated to reduce unserved energy. Effectively, the charging profile of the V2G EVs uplifts the operational load curve during lower demand times and reduces operational peaks.

## C.7 Behind-the-meter battery storage

AEMO provided EY with MW and MWh (degraded) by commercial, large commercial and residential categories of BTM battery storage Facilities.

EY's approach is to run our behind-the-meter storage tool which takes the annual MW and MWh uptake and converts this to a half-hourly charge and discharge profile for each day of the forecast period. The tool assumes that charging and discharging behaviour will be incentivised via tariffs that reflect higher peak demand usage tariffs (to incentivise BTM battery discharging) and lower priced daytime effective tariffs (to incentivise BTM battery charging, due to battery owners being assumed to also own rooftop PV systems).

[45] The calculation of the operational demand value in the constraint equation does not include the demand from utility-scale battery charging. It is also important to note that in real-time operation, AEMO may be required to intervene at demand levels above 500 MW according to the specific fleet configuration and demand uncertainty at the time of intervention.

[46] Note that the 10 vehicle types provided are as follows: 1. Articulated Truck, 2. Bus, 3. Large Light Commercial, 4. Medium Light Commercial, 5. Small Light Commercial, 6. Rigid Truck, 7. Motorcycle, 8. Large Residential, 9. Medium Residential, 10. Small Residential.

Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network, i.e. consumption minus rooftop PV generation. This is based on the rationale that future tariffs will be structured to incentivise battery owners to reduce the difference between the daily minimum and maximum demand as this provides a more optimal network usage. As a result, the tool produces a fixed time-of-day discharge profile that reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand. This profile is produced for each historical reference year of the study.

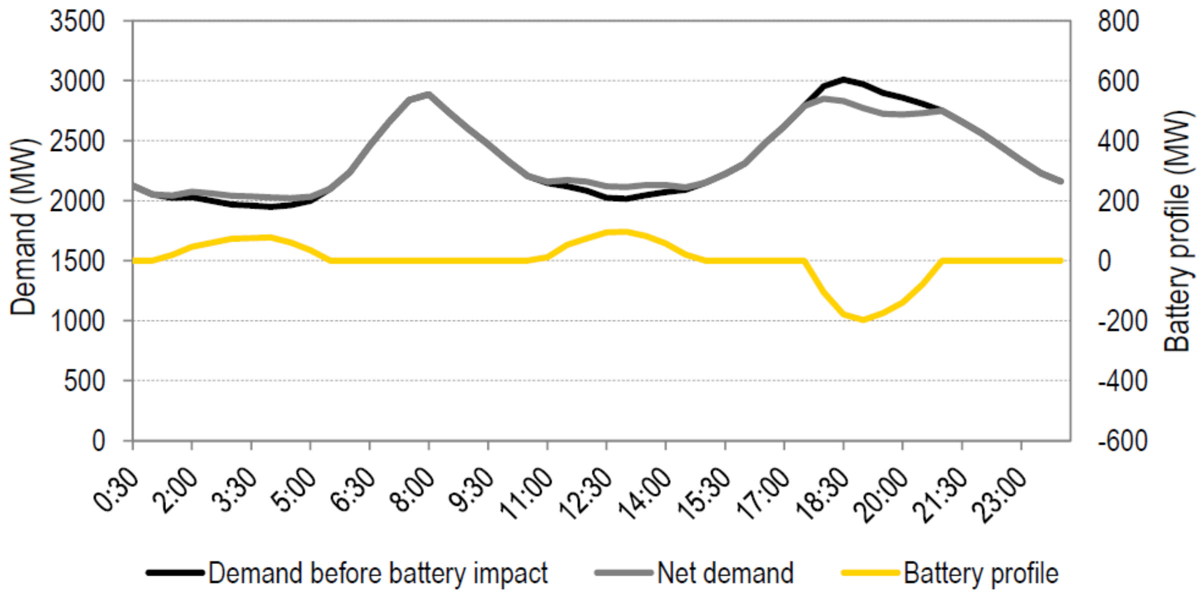
There are two ways in which the tool introduces imperfection to the aggregated profile of the batteries:

► Total energy charge discount factor (50%): To account for the likelihood that battery owners will not fully charge their batteries every day (due to faults, performance degradation, etc.), the daily charge is limited to the selected percentage of the total installed energy capacity of the battery.

► Coincident charge/discharge discount factor (25%): This factor accounts for faults, coordination and the potential for different tariff signals to lead to batteries never being charged or discharged all the same time. The maximum charge or discharge is limited to the selected percentage of the total charge/discharge capacity in MW.

Figure 7 illustrates an example day in winter on how the aggregate battery charge and discharge cycle alters the operational demand profile.

**Figure 7: Illustrative day showing impact of BTM battery storage on operational demand**




## C.8 Modelling block loads/large-industrial loads

EY's default approach is to model large known loads separately from other demand components as outlined above, particularly where these loads have implications for the modelling of network constraints. For this modelling we do not require block loads or large industrial loads to be modelled as separate entities, but did include the collective MW / MWh of these loads to ensure their contribution to peak and overall energy demand in the modelling is aligned with AEMO's annual peak and energy forecasts. Specifically, the demand forecasts and the EY translation of these into half-hourly profiles covered three main large / industrial load components:

► Large industrial loads (LILs): These are modelled with their specific contribution to peak as provided by AEMO, and their energy over the year aligned with the energy consumption provided by AEMO.

► Hydrogen production load: These were modelling assuming that the demand reduced to 10 per cent of installed capacity during peak demand intervals, which for the purposes of this study were assumed to be across 4.30pm to 9.30pm. For the reliability assessment modelling of the expected POE10 scenario, the remainder of hydrogen load was modelled at a MW value for the other hours of the day each day of the year such that the annual energy consumption aligned with AEMO's annual energy forecast.

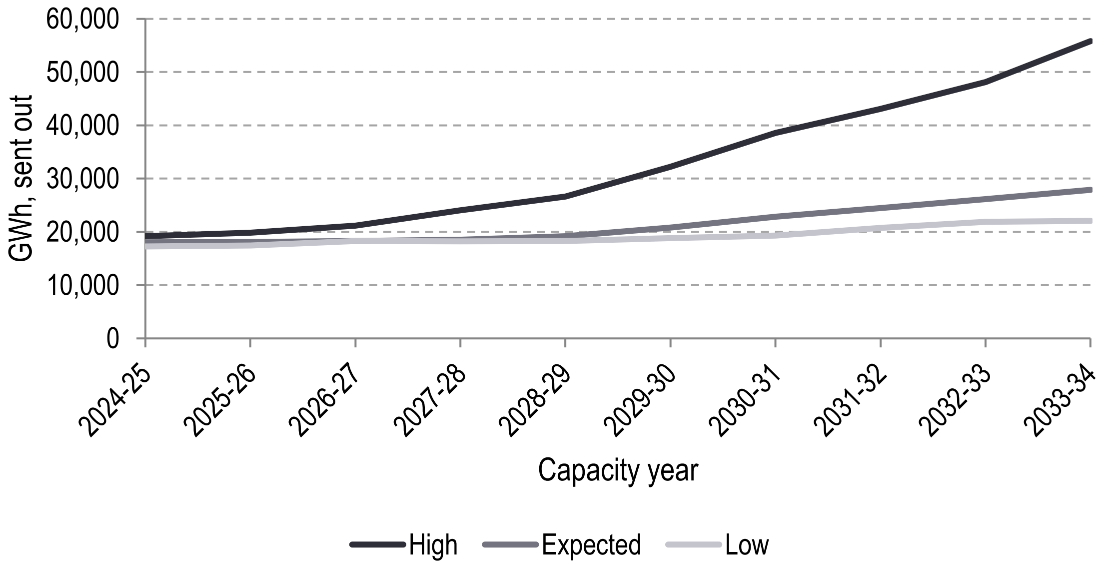
- Electrification load: This was modelled as a flat, non-flexible demand based on the MW associated with the annual energy consumption provided by AEMO.

# Appendix D Modelling assumptions

## D.1 Energy demand

The modelling for the reliability study incorporates AEMO's WEM ESOO 2024 energy consumption forecasts for the expected scenario. Figure 8 presents the annual operational energy consumption in the WEM used in this reliability study. The annual inputs provided by AEMO are converted into half-hourly input data for EY's electricity market model through the process outlined in Appendix C.

**Figure 8: AEMO's 2024 WEM ESOO forecast of annual operational energy consumption in the WEM for the low, expected and high scenarios**




## D.2 Peak demand

The peak demand for electricity is influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The future operational peak demand, to be met by large-scale generators, also depends on the rooftop PV generation, behind-the-meter battery operation and electric vehicle load during the peak periods.

AEMO provides peak demand forecasts for summer and winter in the WEM and for each of these a 10% POE peak demand level. The 10% POE peak demand represents a high demand outcome with a one in ten chance of the peak demand forecast being exceeded in at least one half hour of the year. EY simulates half hourly demand profiles achieving each of these summer and winter peaks.

Figure 9 and Figure 10 show the annual peak demand in the WEM for the summer and winter 10% POE projections respectively, consistent with AEMO's 2024 WEM ESOO scenarios.

**Figure 9: AEMO's 2024 ESOO forecast of annual summer peak operational demand in the WEM for the low, expected, and high scenarios**

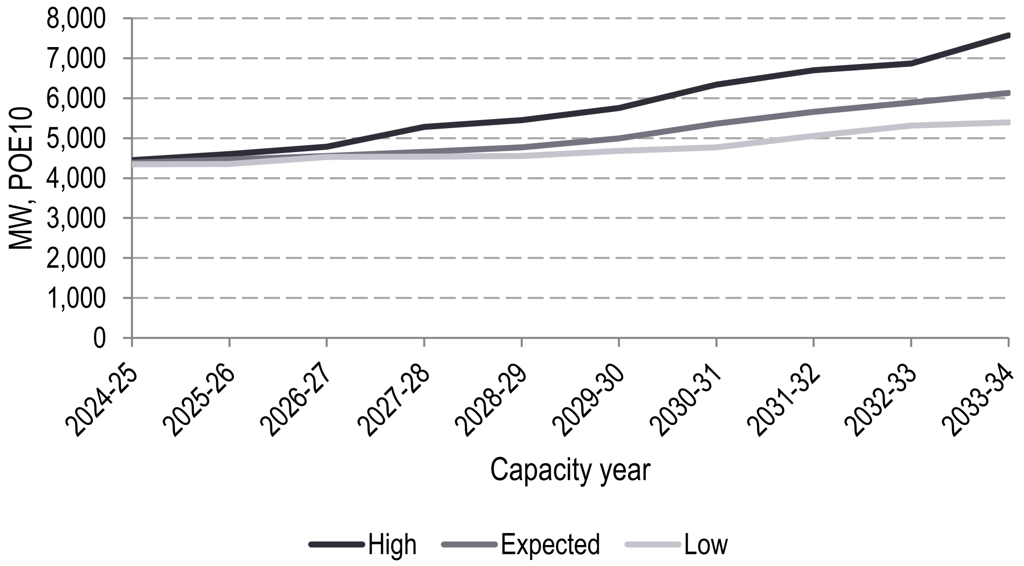
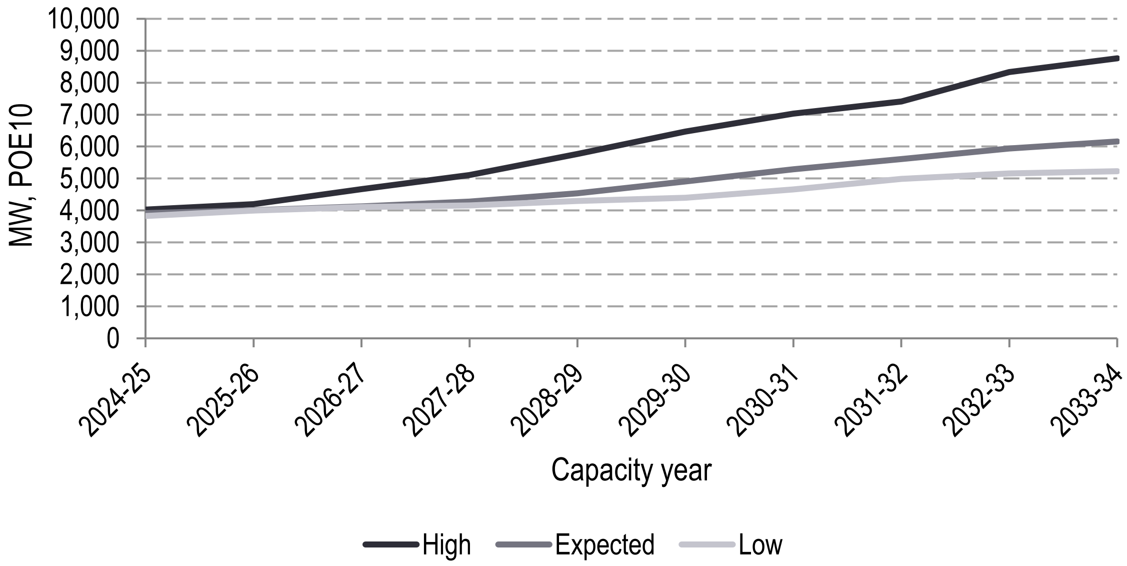



**Figure 10: AEMO's 2024 ESOO forecast of annual winter peak operational demand in the WEM for the low, expected, and high scenarios**




## D.3 Distributed PV

Figure 11 and **Figure 12** show the distributed PV assumptions consistent with AEMO's low, expected and high demand scenarios presented above and including in the modelling, for rooftop PV and small PV non-scheduled generators (PVNSG) respectively.

**Figure 11: Residential and business behind-the-meter rooftop PV forecast generation for low, expected and high demand scenarios**

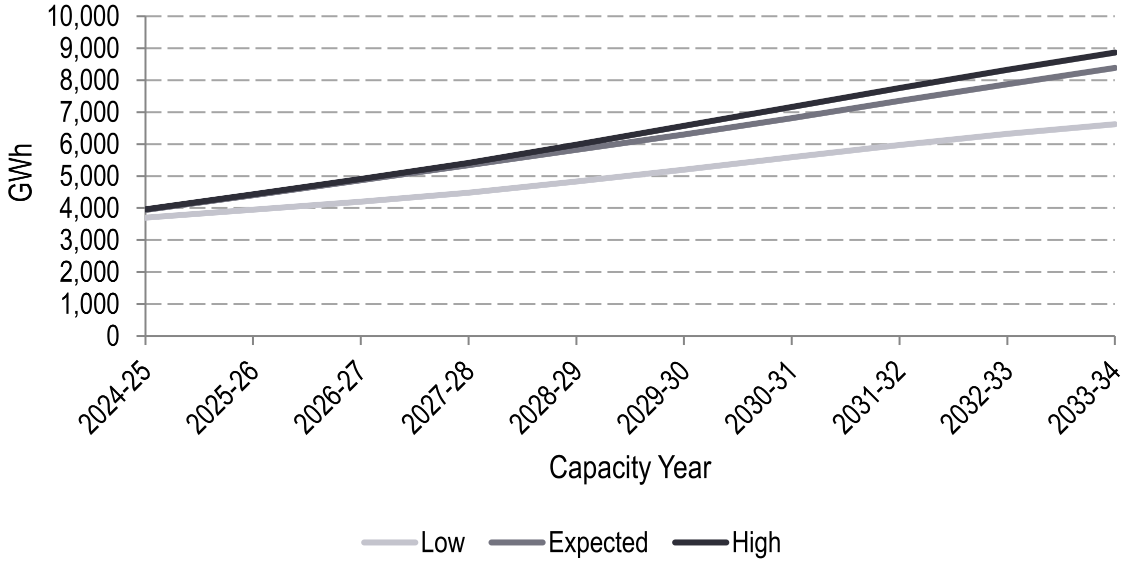
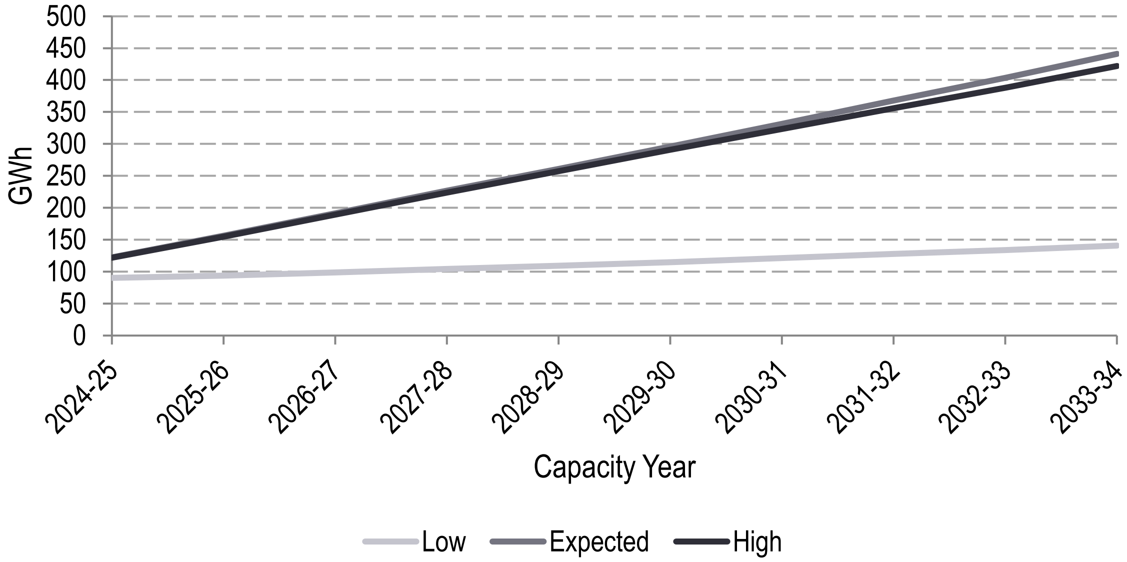



**Figure 12: PVNSG capacity consistent with the low, expected and high demand scenarios**




## D.4 Electric vehicles

Figure 13 provides the annual energy consumption associated with EVs in each of the demand scenarios modelled, while Table 8 sets out the VPP assumptions for EVs. The proportion of EVs by charging profile assumed to participate in co-ordinated charging (through a VPP) is the same in the expected and high scenarios, noting that no co-ordinated charging was assumed for the low scenario. Table 9 provides the daily available MW and MWh for the EV vehicle-to-grid (EV V2G) charge and discharge, noting that no EV V2G was assumed for the low demand scenario.

Figure 13: Energy consumption from electric vehicles consistent with the low, expected and high demand scenarios

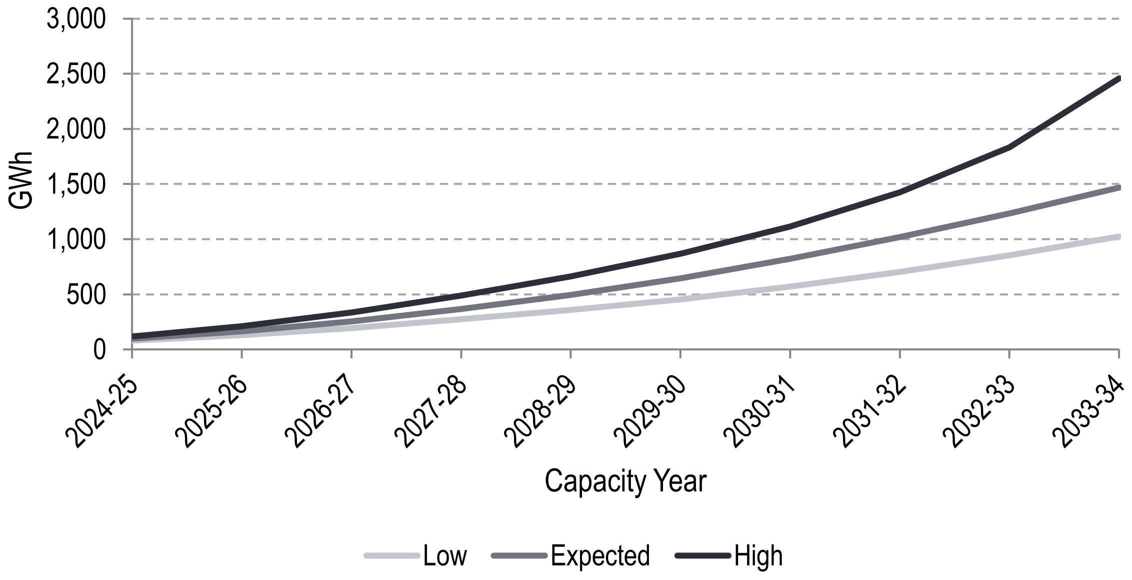



**Table 8: EV consumption assumed to be part of co-ordinated charging in the expected and high scenarios, GWh**

| Financial Year / Demand scenario | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 | 2031-32 | 2032-33 | 2033-34 |
|---|---|---|---|---|---|---|---|---|---|---|
| Expected | - | 0 | 1 | 2 | 3 | 6 | 21 | 44 | 76 | 118 |
| High | - | 0 | 1 | 2 | 4 | 8 | 28 | 62 | 114 | 212 |

**Table 9: EV V2G assumptions for expected and high scenarios**

| Financial Year / Demand scenario | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 | 2031-32 | 2032-33 | 2033-34 |
|---|---|---|---|---|---|---|---|---|---|---|
| Expected | - | - | - | - | - | - | 10 | 24 | 42 | 64 |
| High | - | - | - | - | - | - | 48 | 114 | 201 | 309 |

## D.5 Behind-the-meter storage

Figure 14 presents the assumed uptake of behind-the-meter batteries (residential and commercial uptake) in terms of the total MWh installed capacity (degraded) while Figure 15 presents the proportion of batteries by scenario that are assumed to participate in co-ordinated operation through a VPP.

**Figure 14: Behind-the-meter battery capacity in the low, expected and high demand scenarios**

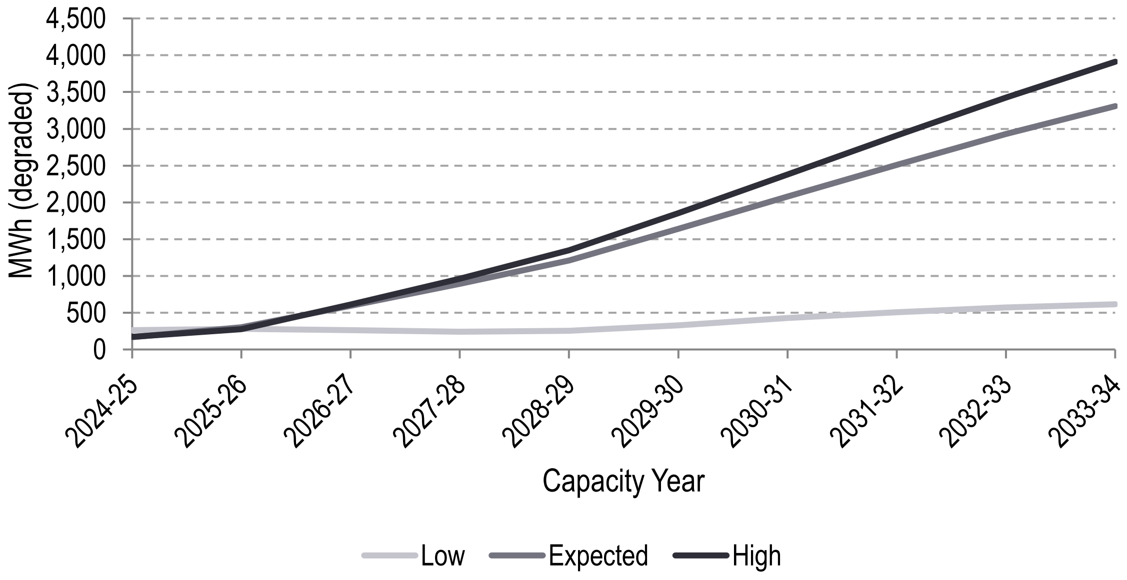
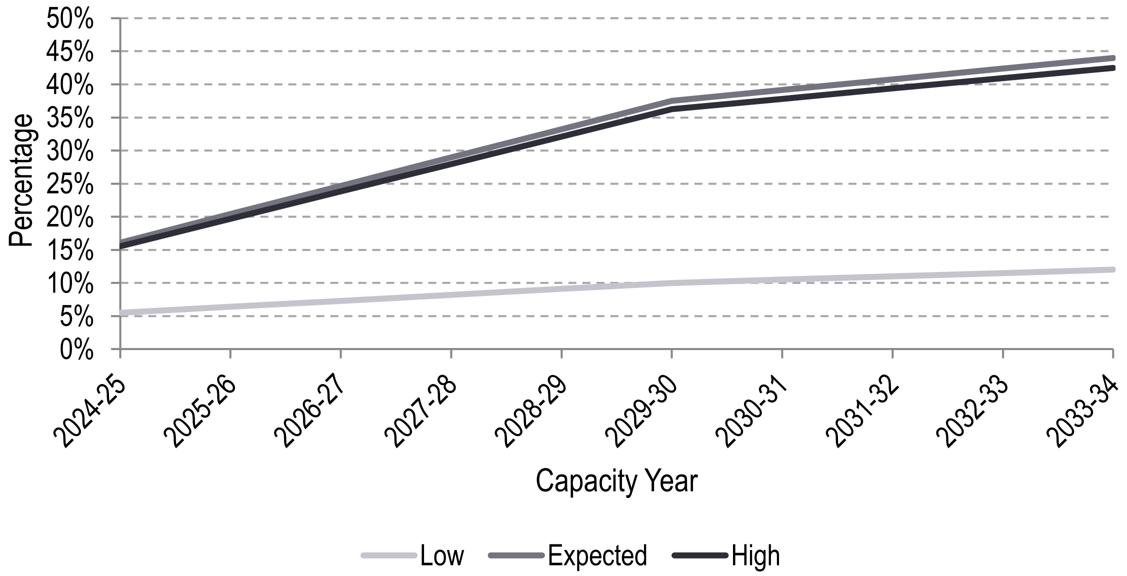



**Figure 15: Proportion of batteries assumed to participate in a VPP in the low, expected and high scenarios**




## D.6 Generation developments

The generation supply side (covering generation, storage and demand side capacity) in the model is based on anticipated installed capacity provided by AEMO. Details of new Facilities entering the WEM (committed) were provided to EY and are as published by AEMO alongside the ESOO. Assumed retirements from the WEM were also provided by AEMO and are as set out in Table 10.

**Table 10: Assumed generator retirements for the reliability study modelling**

| Power station | Technology | Maximum capacity (MW sent out) | Expected scenario retirement date |
|---|---|---|---|
| **MUJA_G6** | Black coal | 193.6 | 1/10/2024 |
| **COLLIE_G1** | Black coal | 318.3 | 1/10/2027 |
| **MUJA_G7** | Black coal | 212.6 | 1/10/2029 |
| **MUJA_G8** | Black coal | 212.6 | 1/10/2029 |

| Power station | Technology | Maximum capacity (MW sent out) | Expected scenario retirement date |
|---|---|---|---|
| **Bluewaters Power Station** | Black coal | 434 | 1/10/2030 |

## D.7 Planned maintenance

Planned maintenance was applied to units in line with the methodology set out in Section B.1.6. Where maintenance data was available from AEMO's FIR process, this was applied in the modelling, otherwise assumed maintenance periods were applied to technologies as set out below in

**Table 11: Assumed planned maintenance periods applied to Facilities and / or years FIR data not available**

| Technology | Equivalent average days per year on planned maintenance |
|---|---|
| **Black coal** | 20 |
| **CCGT** | 20 |
| **OCGT** | 5 |
| **Diesel** | 6 |
| **Cogeneration** | 20 |
| **Waste to energy** | 23 |
| **Battery gen** | 0 |

## D.8 Forced outages

AEMO provided EY with forced outage rate statistics based on an assessment of published outage These rates were applied in the modelling where available, otherwise generic rates by technology were applied as set out in Table 12 (for example for new Facilities).

**Table 12: Outage rates by technology applied where outage statistics not otherwise available**

| Facility Code | Full outage rate | Full outage – mean time to repair | Partial outage rate | Partial outage - mean time to repair | Partial outage derating factor |
|---|---|---|---|---|---|
| **Black coal** | 4.3% | 104 | 23.8% | 17 | 17.51% |
| **CCGT** | 1.7% | 23 | 0.2% | 29 | 36.52% |
| **OCGT** | 1.3% | 7 | 0.4% | 40 | 11.96% |
| **Diesel** | 3.5% | 16 | 0.4% | 35 | 7.18% |
| **Cogeneration** | 1.7% | 23 | 0.2% | 29 | 36.52% |
| **Waste to energy** | 3.0% | 40 | 2.0% | 7 | 30.00% |
| **Battery gen** | 1.5% | 48 | 3.0% | 96 | 20.00% |

# Appendix E Glossary of terms

| Term | Meaning |
|---|---|
| **2-4-C®** | EY's in-house time-sequential market dispatch modelling suite. |
| **Anticipated Installed Capacity** | Existing SWIS installed capacity (generation, storage, DSM) less existing capacity retirements + committed capacity Facilities (as applicable by scenario settings). |
| **Capability Class 1** | Firm capacity that is not energy limited, such as a gas-fired Facility that meets the fuel availability requirements. |
| **Capability Class 2** | Firm capacity with energy or availability limitations, such as battery, pump storge hydro or a DSP. |
| **Capability Class 3** | Non-firm capacity, such as a wind or solar farm with no associated firming capability. |
| **business** | Includes industrial and commercial users. |
| **Capacity Credit** | A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equal to 1 MW of capacity. |
| **capacity factor** | Actual energy output over a given period of time as a proportion of the theoretical maximum output over that period. |
| **Capacity Year** | "A Capacity Year commences in the Trading Interval starting at 8:00 AM on 1 October and ends in the Trading Interval ending at 8:00 AM on 1 October of the following calendar year." |
| **Consumption** | The amount of power used over a period of time, conventionally reported as megawatt hours (MWh) or gigawatt hours (GWh) depending on the magnitude of power consumed. It is reported on a “sent-out” basis (excluding electricity used by a generator) unless otherwise stated. |
| **Demand** | The amount of power consumed at any time. Peak and minimum demand is measured in MW and averaged over a 30-minute period. It is reported on a “sent-out” basis (excluding electricity used by a generator) unless otherwise stated. |
| **demand side management (DSM)** | A type of capacity held in respect of a Facility connected to the SWIS; specifically, the capability of a Facility connected to the SWIS to reduce its consumption of electricity through the SWIS, as measured at the connection point of the Facility to the SWIS |
| **demand side programme (DSP)** | Facility comprising one or more Non-Dispatchable Loads that can be curtailed on request by AEMO, registered in accordance with clause 2.29.5A. |
| **distributed battery storage** | Behind-the-meter battery storage systems installed for residential, commercial, and large commercial, that do not hold Capacity Credits in the WEM. |
| **Consumer energy resource (CER)** | CER includes distributed PV, distributed battery storage, and electric vehicles. |
| **distributed photovoltaics (DPV)** | DPV includes both behind-the-meter rooftop PV and PVNSG. |
| **economic spill** | Relates to the scenario where interval demand is such that available wind and solar resource is not fully utilised. |
| **Electric Storage Resource (ESR)** | One or more energy storage assets that are electrically connected to the SWIS at the same connection point. |
| **Electric Storage Resource Obligation Intervals (ESROIs)** | The Electric Storage Resource Obligation Intervals (ESROI) are a set of 8 contiguous Trading Intervals during which an Electric Storage Resource (ESR) is obligated to be available under the Reserve Capacity Mechanism (RCM). |
| **electric vehicle** | Electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses. |
| **emergency solar management** | Refers to the capability to remotely reduce the generation from small-scale distributed rooftop solar PV systems as a last resort measure, assisting AEMO to protect the power system during extreme low load events. |
| **energy producing system** | Generation capacity in the SWIS consisting of thermal, renewable, storage capacity |
| **expected unserved energy** | Unserved energy means the amount of customer demand that cannot be supplied in a region of the national electricity market due to a shortage of generation or interconnector capacity. It is calculated in megawatt or gigawatt hours (MWh or GWh) and is typically expressed in terms of a percentage of customer demand. The term expected unserved energy means a statistical expectation of a future state; an average across a range of future outcomes, weighted for probability. |

| Term | Meaning |
| --- | --- |
| **Facility** | The following are Facilities in the WEM: (a) a distribution system; (b) a transmission system; (c) a generation system; (d) a connection point at which electricity is delivered from a distribution system or transmission system to a Rule Participant ("Load"); and (e) a Demand Side Programme. |
| **forced and partial outage** | Unplanned shut down of a generating Facility. In the case of a partial outage, a proportion of the Facility's capacity is modelled as unavailable. Each Facility has a probability of experiencing a forced (unplanned) outage at any one time. Monte Carlo simulations of forced outages assign full and partial forced outages to each generating unit based on the assumed probabilities. |
| **Intermittent generator** | A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g., wind speed). |
| **Interruptible Load** | A load through which electricity is consumed, where such consumption can be curtailed automatically in response to a change in system frequency and registered as such in accordance with clause 2.29.5 of the WEM rules. |
| **iteration** | Half-hourly modelling of a single possible outcome for a future set of years. |
| **Large Industrial Loads** | Users that consume, or are forecast to consume, at least 10 MW for at least 10% of the time (around 875 hours a year). |
| **Limb A** | Term attributed to the requirement of the Planning Criterion that stipulates that there should be sufficient available capacity in each Capacity Year to meet the forecast peak demand plus a reserve margin. |
| **Limb B** | Term attributed to the requirement of the Planning Criterion that stipulates there should be sufficient available capacity in the SWIS to limit expected unserved energy (EUE) shortfalls to 0.0002% of annual energy consumption. |
| **load shedding** | The controlled reduction of electricity supply to parts of the power system servicing homes and businesses to protect system security and mitigate damage to infrastructure. |
| **maximum capacity** | The net sent-out generation or installed capacity of a Facility, as detailed on AEMO's Market Data website. |
| **Not-summer seasonal rating** | Seasonal rating applied to months outside of November to March. |
| **operational** | Electricity consumption (demand) that is met by sent -out electricity supply of all market-registered energy. |
| **operational consumption** | Electricity consumption (demand) that is met by sent-out electricity supply of all market registered energy producing systems. It includes losses incurred from the transmission and distribution of electricity and electricity consumption (demand) of EVs but excludes electricity consumption (demand) met by DPV generation. |
| **peak demand** | MW value for maximum demand supplied through the SWIS (operational peak demand) for a single 30-minute interval in a Capacity Year. Peak demand refers to operational peak demand unless otherwise stated. |
| **peaking capacity** | Facilities that generally operate less than 10% of the time. |
| **probability of exceedance (POE)** | The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded on average once in every 10 years. |
| **Projected Assessment of System Adequacy (Long Term PASA)** | Forecasting study undertaken by AEMO on an annual basis, as part of the publishing of the Electricity Statement of Opportunities (ESOO) for the Wholesale Electricity Market. It takes into consideration a 10-year planning horizon for generation, demand side programs, and network capacity. |
| **ramp rates** | Speed at which a Facility can increase (ramp up) or decrease (ramp down) generation or demand. |
| **Reference year** | Future half-hourly demand, wind and solar PV generation is modelled based on several historical reference years to capture a variety of Australian weather patterns. |
| **Reliability Standard** | The Planning Criterion defined in clause 4.5.9 of the WEM Rules. |
| **Reserve Capacity Cycle** | A period covering the cycle of events described in clause 4.1 of the WEM Rules. |
| **Reserve Capacity Mechanism** | Set out in Chapter 4 of the WEM Rules, it is aimed at ensuring that there is sufficient capacity in the South West interconnected system (SWIS). |
| **Reserve Capacity Price (RCP)** | In respect of a Reserve Capacity Cycle, the price for Reserve Capacity determined in accordance with clause 4.29.1, where this price is expressed in units of dollars per Capacity Credit per year. |
| **Reserve Capacity Target (RCT)** | AEMO's estimate of the total quantity of generation or DSM capacity required in the SWIS to satisfy the Planning Criterion. |
| **residential** | Includes residential customers only. |

| Term | Meaning |
|---|---|
| **rooftop photovoltaics** | Systems comprising of one or more photovoltaic panels, installed on a residential building (less than 15 [kW]) or business premises (less than 100 kW) to convert sunlight into electricity. |
| **Solar Energy Simulation Tool (SEST)** | EY's in-house tool used to develop half-hourly PV availability profiles for existing and potential solar farms used in the modelling. |
| **Summer seasonal rating** | Seasonal rating applied to all periods in the months from November to March inclusive. |
| **Supplementary Reserve Capacity** | Supplementary Reserve Capacity (SRC) will be procured by AEMO if, at any time after the day that is six months before the start of a Capacity Year, it determines that insufficient capacity is available to satisfy demand. |
| **Time-sequential data** | Mean time series of 17,520 (or 17,568 for leap years) consecutive 30-minute interval datapoints for each modelled year, with outcomes in the previous interval being relevant for the currently modelled interval. |
| **Trading Interval** | Defined in the WEM Rules as a period of 30 minutes commencing on the hour or half-hour during a Trading Day |
| **transmission network constraint equations** | Linearised mathematical expressions that represent the technical envelope that the SWIS must operate within. They model the maximum power transfer that can flow on transmission network elements before a limitation is reached. |
| **underlying consumption/demand** | The total amount of electricity consumption (demand) by electricity users from their power points regardless, if it is supplied from the grid or by behind-the-meter (typically rooftop PV) generation. |
| **virtual power plant** | An aggregation of resources (such as decentralised generation, storage, and controllable loads) co-ordinated to deliver services for power system operations and electricity markets. |
| **Wind Energy Simulation Tool (WEST)** | EY's in-house tool used to develop half-hourly, time sequential, locational wind availability profiles for existing and potential wind farms used in the modelling. |

**EY** | Building a better working world

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